CLASS VI PERMIT APPLICATION NARRATIVE
40 CFR 146.82(a)

Facility Information

Facility name:	Kemper County Storage Complex
	Well Name: MPC 19-2
Facility contact:	Mississippi Power Company
	Environmental Affairs
	P.O. Box 4079
	Gulfport, MS 39502-4079
Well location:	Kemper County, Mississippi
	Latitude: 32.6130560; Longitude: -88.8061110

Table of Contents

A. Project Background and Contact Information 8
A.1. The Project 8
A.2. Proposed CO_2 source and mass/volume of injection 11
A.3. Project timeframe 11
A.4. Partners/Collaborators/Stakeholders 12
B. Site Characterization 14
B.1. Regional Geology, Hydrogeology, and Local Structural Geology [40 CFR 146.82(a)(3)(vi)] 14
B.1.a. Physiography of Proposed Kemper County Storage Complex 14
B.1.b. Structural Setting of the Kemper County Storage Complex 14
B.1.c. Cenozoic and Mesozoic Stratigraphy at the Proposed Kemper County Storage Complex 19
B.1.d. Storage zone 22
B.1.e. Hydrogeology 23
B.2. Maps and Cross Sections of the AoR [40 CFR 146.82(a)(2), 146.82(a)(3)(i)] 25
B.3. Faults and Fractures [40 CFR 146.82(a)(3)(ii)] 47
B.4. Injection and Confining Zone Details [40 CFR 146.82(a)(3)(iii)] 47
B.4.a Tuscaloosa Marine shale 52
B.4.b Lower Tuscaloosa 53
B.4.c Upper Washita-Fredericksburg shale 54
B.4.d. “Big Fred” Sand 54
B.4.e Washita- Fredericksburg Basal Shale 55
B.4.f. Paluxy Formation 55
B.5. Geomechanical and Petrophysical Information [40 CFR 146.82(a)(3)(iv)] 58
B.6. Seismic History [40 CFR 146.82(a)(3)(v)] 60
B.7. Hydrologic and Hydrogeologic Information [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)] 64
B.8. Geochemistry [40 CFR 146.82(a)(6)] 69
B.8.a. Paluxy Formation Mineralogy (Solid-Phase Geochemistry – Injection Interval) 69
B.8.b. Marine Tuscaloosa Shale (Solid-Phase Geochemistry – Confining Zone) 70
B.8.c. Pore-fluid Chemistry of the Injection Zone and Shallow USDWs 70
B.9. Other Information (Including Surface Air and/or Soil Gas Data, if Applicable) 73
B.10. Site Suitability [40 CFR 146.83] 73
C. AoR and Corrective Action 74
D. Financial Responsibility 74
E. Injection Well Construction 75
E.1. Well Design 75

E.2. Maximum Wellhead Injection Pressure 75
E.3. Casing Program 75
E.4. Casing Summary 79
E.4.a. Conductor Casing 81
E.4.b. Surface Casing 81
E.4.c. Long-String Casing 81
E.4.d. Tubing 81
E.5. Cementing Program 82
E.6. Annular Fluid 83
E.7. Wellhead 84
E.8. Perforations 87
E.9. Schematic of the Subsurface Construction Details of the Well 87
F. Pre-Operational Logging and Testing 89
G. Well Operation 89
G.1. Proposed Characteristics of Carbon Dioxide Stream [40 CFR 146.82(a)(7)(iii) and (iv)] 90
G.2. Corrosiveness of the Carbon Dioxide Stream 91
G.3. Operational Procedures [40 CFR 146.82(a)(10)] 91
G.3.a. Operational Conditions 91
G.3.b. Operational Protocols 94
H. Testing and Monitoring 96
I. Injection Well Plugging 96
J. Post-Injection Site Care (PISC) and Site Closure 98
K. Emergency and Remedial Response 99
L. Other Information 100

List of Figures

Figure 1. Regional View of the two Southern Company Power Plants providing CO_2 for the Project. 9

Figure 2. Location of the Plant Ratcliffe in Kemper County, Mississippi. 10

Figure 3. Kemper County Storage Complex. Showing Project Characterization and Proposed Injection Well Locations. 10

Figure 4. Map of the Surface Geology in Mississippi with Physiographic Regions. Inset map shows the Location of Proposed Kemper County Storage Complex 15

Figure 5. Generalized Structural Setting of Kemper County Storage Complex in Central Mississippi 16

Figure 6. Interpreted Seismic Profile Near the Kemper County County Storage Complex, which shows the relationship between Paleozoic strata of the Appalachian-Ouachita Oregen and gently dipping deposits of the Mississippi Embayment. (Seismic formation licensed to the Geological Survey of Alabama by Seismic Exchange, Incorporated). 17

Figure 7. Exoduas 2D Seismic Lines 2021 Survey. A: Map view of seismic profile line relative to proposed injection wells. B: Seismic profile with formation tops and approximate location of MPC 19-2. 18

Figure 8. Composite “Type” Log, for Mesozoic-Cenozoic Formations at the Proposed Kemper County Storage Complex. GR = Gamma Ray. Each log is showing increasing values from left to right. 24

Figure 9. Characterization Wells Full cross-section. The cross-section is flattened on the Maximum Flooding Surface in the Tuscaloosa Marine Shale interval. 26

Figure 10. Characterization Well Cross-section of the Injection Zone. Gamma ray (API) is in track 1, and resistivity (Ohm-meter) is in track 2 for each well. The cross-section is flattened on the Maximum Flooding Surface in the Tuscaloosa Marine Shale interval. 27

Figure 11. Contour Map Data Limits, including well locations, well names, and the Area of Review outline (red dashed line). 28

Figure 12. Top of Tuscaloosa Marine Shale Structure Map 29

Figure 13. Tuscaloosa Marine Shale Gross Isopach Map 30

Figure 14. Top of Lower Tuscaloosa shale Structure Map 31

Figure 15. Lower Tuscaloosa Gross Isopach map 32

Figure 16. Net shale map (ft) of the interval from the top of the Tuscaloosa Marine Shale to the top of the Massive sand. 33

Figure 17. Top of Massive Sand Structure Map 34

Figure 18. Massive Sand Gross Isopach Map 35

Figure 19. Dantzler Formation Structure Map 36

Figure 20. Dantzler Formation Gross Isopach Map 37

Figure 21. Top of Upper Washita-Fredericksburg Shale Structure Map 38

Figure 22. Upper Washita-Fredericksburg Shale Gross Isopach Map 39

Figure 23. Top of “Big Fred” Sand Structure Map 40

Figure 24. "Big Fred" Sand Gross Isopach Map 41
Figure 25. Top of Basal Washita-Fredericksburg Shale Structure Map 42
Figure 26. Basal Washita-Fredericksburg Shale Gross Isopach Map 43
Figure 27. Top of Paluxy Formation Structure Map 44
Figure 28. Paluxy Formation Gross Isopach Map 45
Figure 29. Net sand map of the Paluxy formation 46
Figure 30. Tuscaloosa Marine Shale Core from MPC 10-4. 53
Figure 31. Paluxy Core from Well MPC 10-4. 57
Figure 32. Paluxy Core from Well MPC 34-1. 58
Figure 33. Seismic Hazard Map for Mississippi (Source: USGS, 2014) 61
Figure 34. Earthquake Epicenters in Mississippi. 63
Figure 35. Shallow groundwater wells around the Kemper County Storage Complex 66
Figure 36. Nodal Analysis Design Schematic 76
Figure 37. Inflow Performance Relationship (IPR) for 4.5 inch injection tubing 77
Figure 38. Illustration of the Wellhead Configuration. 86
Figure 39. Preliminary Injection Well Schematic 88

List of Tables

Table 1. Cenozoic and Mesozoic Stratigraphic Units at Proposed Kemper County Storage Complex. 20
Table 2. Well Core Depths from the Characterization Wells 49
Table 3. Tabulation of mudstone porosity and permeability data 50
Table 4. Tabulation of sandstone porosity, permeability, and capacity data. 51
Table 5. Elastic mechanic properties determined from the Uniaxial Pore Volume Compressibility tests. 59
Table 6. Historical Earthquakes Recorded in Kemper County and Vicinity. 64
Table 7. Geologic Units and Principal Aquifers in Central Mississippi. Source: 65
Table 8. Geochemical water quality results determined from fluid samples taken by the Positive Displacement Bottom Hole Sample Tool from four different characterization wells in Kemper County, Mississippi. 72
Table 9: Geochemical water quality results determined from fluid samples taken by the Positive Displacement Bottom Hole Sample Tool from four different characterization wells in Kemper County, Mississippi. 72
Table 10. Load Scenarios Evaluated 78
Table 11. Calculated Safety Factors for the Proposed Tubular Program 78
Table 12. Borehole and Casing Program for the CO_2 Injection Well 79
Table 13. Properties of Well-Casing Materials 80
Table 14. Calculated Safety Factors for the Proposed Injection Tubing 82
Table 15. Cementing Program 82
Table 16. Materials Specification of Wellhead and Christmas Tree 85
Table 17. Material Classes from API 6A (Specification for Wellhead and Christmas Tree Equipment) 85
Table 18. CO_2 Injection Stream Composition 91
Table 19. Inputs to Wellbore Calculations in Pipesim ® 92
Table 20. Proposed operational procedures 92
Table 21. Proposed operational procedures 94

List of Acronyms/Abbreviations

AoR	Area of Review
CCUS	Carbon capture, utilization, and storage
CO_2	Carbon dioxide
CMG	Computer Modelling Group
DOE	Department of Energy
ECO_2S	Establishing An Early Carbon Dioxide Storage
EPA	Environmental Protection Agency
ERRP	Emergency and Remedial Response
ft	feet
mg/L	milligrams per liter
MMt	Millions of Metric tons
MPC	Mississippi Power Company
PCC	Porters Creek Clay
PISC	Post-Injection Site Care
psi	Pounds per square inch
RCA	Routine Core Analysis
SS	Sub- Sea
TMS	Tuscaloosa Marine Shale
TVD	True Vertical Depth
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water

A. Project Background and Contact Information

GSDT Submission - Project Background and Contact Information
GSDT Module: Project Information Tracking ***Tab(s):*** General Information tab; Facility Information and Owner/Operator Information tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Required project and facility details ***[40 CFR 146.82(a)(1)]***

A.1. The Project

This Project, supported by the U.S. Department of Energy-National Energy Technology Laboratory (DOE-NETL), hosted by Mississippi Power Company (MPC) and Southern Company, and managed by the Southern States Energy Board (SSEB) and Advanced Resources International, Inc. (ARI), is working towards the development of a regional CO_2 Storage Complex in Kemper County, Mississippi. The property is located directly adjacent to MPC's Plant Ratcliffe and the local geology has demonstrated excellent CO_2 storage and confinement characteristics [1].

Post-combustion CO_2 will be captured from MPC's natural gas power generation units at Plant Ratcliffe and Plant Daniel (**Figure 1**) and transported via pipeline to the Kemper County Storage Complex (**Figures 2 and 3**), where it will be injected via two Class VI permitted wells. No depth waiver or aquifer exemption is requested for this project since the proposed injection interval is greater than 4,000 ft deep and the reservoir fluid has been determined to be saline in nature, with total dissolved solids (TDS) greater than 25,000 mg/L. Fit-for-purpose monitoring protocols have been laid out to allow the project team to track the progress of the injected CO_2 and development of pressure plumes through well-based observation, thereby providing data inputs to numerical models to allow continuous interpretation of the flow profile development to ensure containment of the injectant.

[1] Pashin, J. C., Achang, M., Martin, S., Urban, S. K., & Wethington, C. L. R. (2020). Commercial-scale CO2 injection and optimization of storage capacity in the southeastern United States (Project ECO2S, Kemper County energy facility, Mississippi): US Department of Energy. *National Energy Technology Laboratory Final Report (funded through the Southern States Energy Board and Advanced Resources International), contract DE-FE001055.*

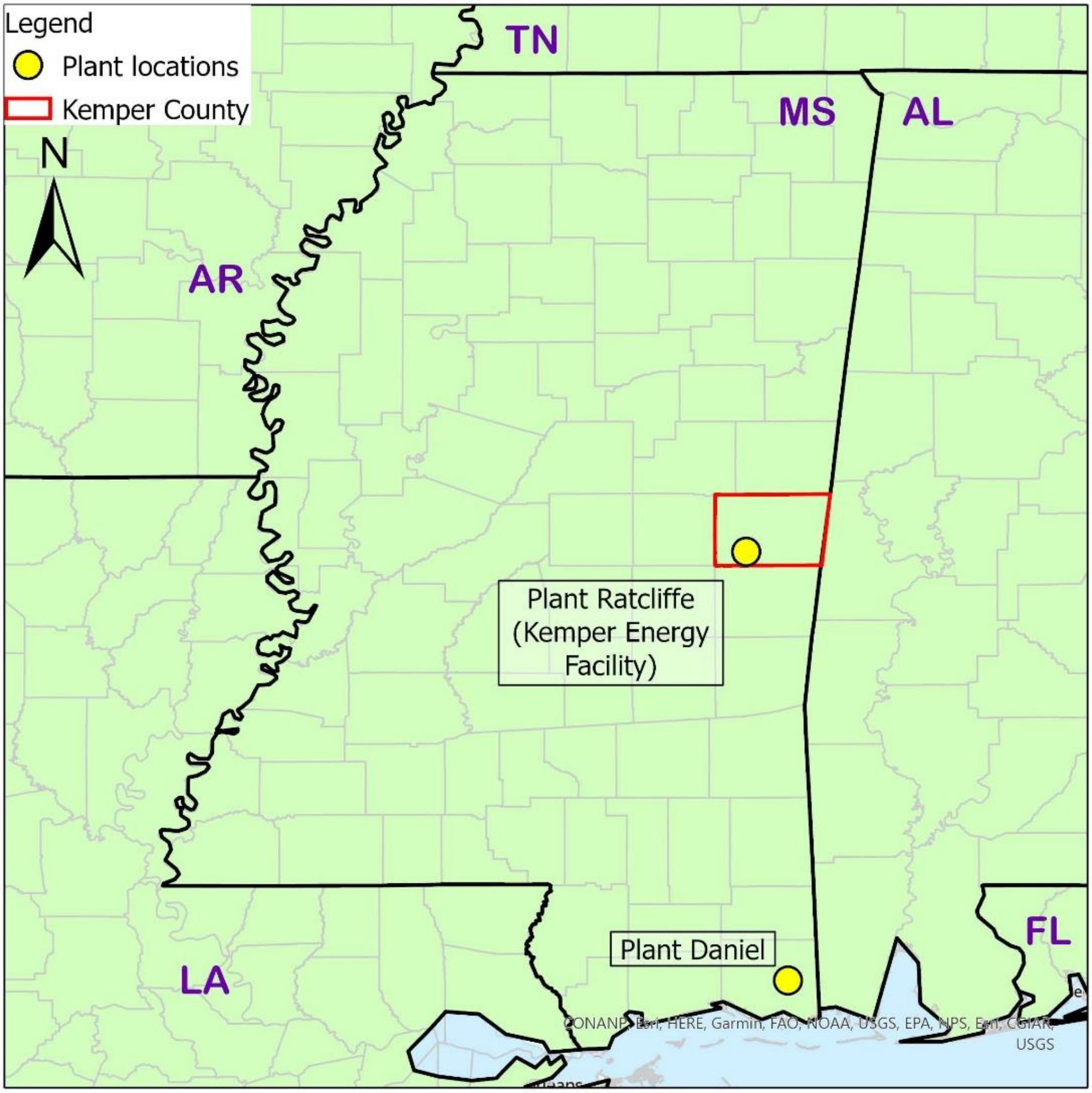

Figure 1. Regional View of the two Southern Company Power Plants providing CO_2 for the Project.

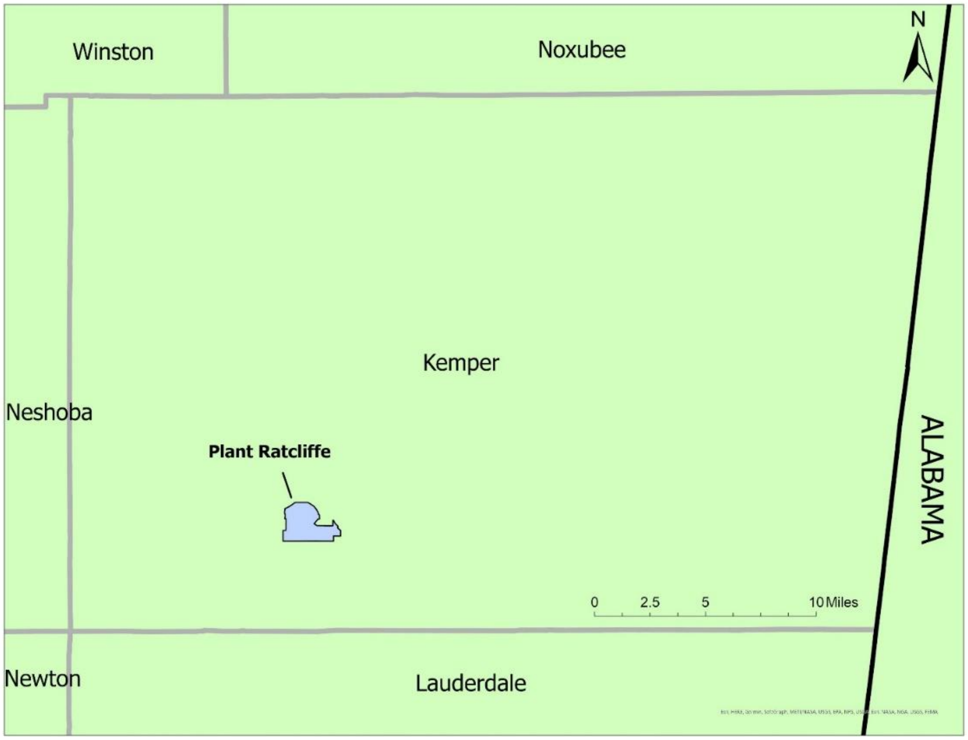

Figure 2. Location of the Plant Ratcliffe in Kemper County, Mississippi.

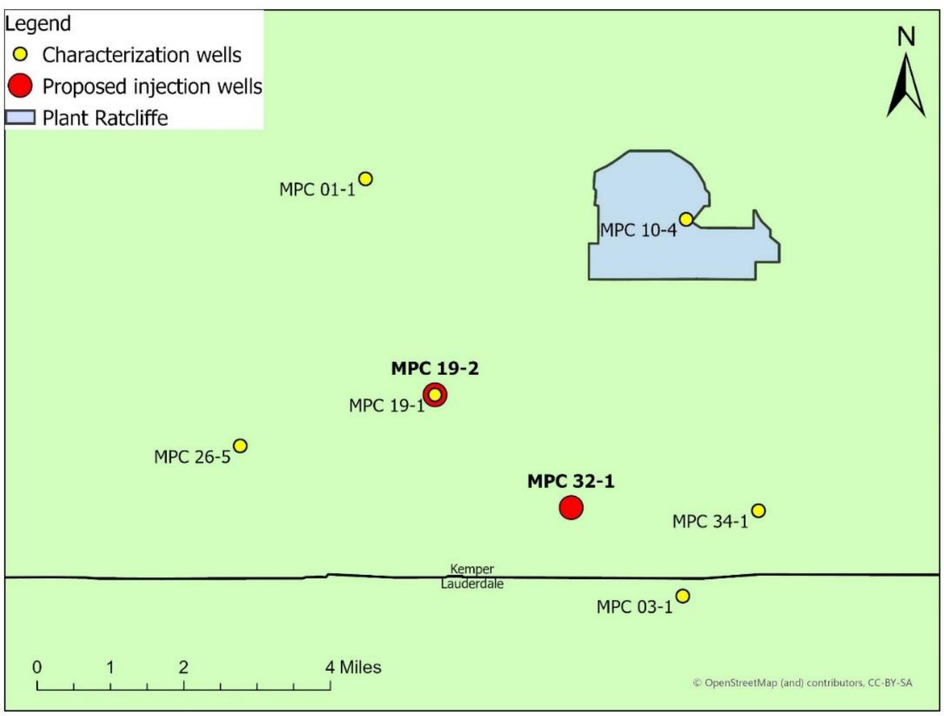

Figure 3. Kemper County Storage Complex. Showing Project Characterization and Proposed Injection Well Locations.

The Kemper County Storage Complex will provide safe, secure, and long-term CO_2 storage for a substantial portion of Southern Company's CO_2 emissions from power plants. In future years, the Storage Complex could also provide a viable storage option for CO_2 captured from additional power plants and other industrial sources in the region. Further, given the significant number of coal-fired generators still operated by Southern Company, the Project is in a unique position to provide the industry with real solutions to support its carbon management reduction goals.

The primary goals of the Project are to:

A. Reduce CO_2 emissions from Southern Company facilities to help the site hosts meet their commitment to a low-carbon future,

B. Geologically store more than 50 Mt of CO_2 over 30 years, and

C. Monitor the subsurface CO_2 movement to ensure safe, secure, and long-term geological storage.

A.2. Proposed CO_2 source and mass/volume of injection

The sources of CO_2 for the Project originate from two MPC generation plants; Plant Ratcliffe and Plant Daniel (**Figure 1)**. Plant Ratcliffe is estimated to provide 0.7 - 0.9 Mt of captured CO_2 per year and is located adjacent to the Kemper County Storage Complex. Plant Daniel is less than 150 miles to the south of the Kemper County Storage Complex and is estimated to provide 2 Mt of captured CO_2 per year. The two injection wells will be capable of storing 8,000 tons / day, which is roughly equivalent to 90% of the total emissions from Plants Daniel and Ratcliffe over 30 years.

A.3. Project timeframe

In 2019, Southern Company announced their commitment to transitioning its power generation-fleet to a low-carbon future, including a goal of "a 50 percent reduction in carbon emissions (from 2007 levels) by 2030 and meeting a long-term goal of low- to no-carbon operations by 2050" [2]. A major component of Southern Company's CO_2 emissions reduction strategy includes implementing carbon capture and geologic storage, which removes CO_2 from the atmosphere and stores it underground in geological formations to reduce carbon emissions over time.

[2] Southern Company (2020). Implementation and action toward net zero.

The characterization phase of the Project began in 2017 with the drilling of three characterization wells in the Kemper County Storage Complex (MPC 10-4, MPC 26-5, and MPC 34-1; **Figure 3**). Three more characterization wells were drilled over 2020 and 2021 (MPC 01-1, MPC 03-1, and MPC 19-1).

Two proposed injection wells will be permitted at the Kemper County Storage Complex: the first proposed injection well (MPC 19-2) will be on the same pad as the MPC 19-1, and the second proposed injection well (MPC 32-1) will be located approximately 2 miles to the southeast. The two proposed injection wells will accommodate the proposed volume of CO_2 provided from the natural gas combustion at MPC's Plant Ratcliffe and Plant Daniel.

In parallel to the injection site development, studies are currently ongoing to develop front-end engineering designs for the carbon capture facilities and transportation infrastructure. To pull this multi-faceted Project together, it is anticipated that the 30-year injection period will start in 2025, end in 2055, and be followed by a 20-year post-injection site care period, taking the Project to 2075.

A.4. Partners/Collaborators/Stakeholders

MPC and Southern Company have made major, corporate-level commitments toward the development of the Kemper County Storage Complex. MPC will serve as the project owner and will assume liability of the project development, finance, and operation, with support from federal- and state-level agencies.

The Project will be carried out in entirely within the State of Mississippi and focused on Kemper and Lauderdale counties. No tribal or territory boundaries will be impacted per 40 CFR 146.82(a)(20). Key contacts are:

Mississippi Power Company
Name/Agency, title, phone, email

Advanced Resources International, Inc.
Name/Agency, title, phone, email

Southern Company
Name/Agency, title, phone, email

Southern States Energy Board
Name/Agency, title, phone, email

The State of Mississippi
Name/Agency, title, phone, email

Kemper county, MS
Name/Agency, title, phone, email

Lauderdale county, MS
Name/Agency, title, phone, email

B. Site Characterization

B.1. Regional Geology, Hydrogeology, and Local Structural Geology [40 CFR 146.82(a)(3)(vi)]

B.1.a. Physiography of Proposed Kemper County Storage Complex

Mississippi is divided into several physiographic subdivisions, which represent varying topographic profiles induced by differential erosion of geologic bedrock. As a result, the boundaries of these regions generally parallel geologic outcrops [3]. The Kemper County Storage Complex is located within Mississippi's North Central Hills physiographic region (**Figure 4**) which overlies the predominately sandy units of the Eocene-aged Claiborne Group and the Eocene-Paleocene Wilcox Group [4]. The Wilcox Group outcrops along the eastern boundary of the North Central Hills province and is the recharge area for Eocene and Paleocene aquifers.

B.1.b. Structural Setting of the Kemper County Storage Complex

Kemper County is underlain by over 26,000 ft of sedimentary rock of Cambrian through Tertiary age which nonconformably overlies the Precambrian crystalline basement [5]. Paleozoic strata range in age from Cambrian through Pennsylvanian and were deposited near the southern limit of the Black Warrior Basin, at what is now the buried juncture of the Appalachian and Ouachita tectonic belts in central and southern Kemper County (**Figure 5**) [6] [7].

[3] Mallory, M. J. (1993). Hydrogeology of the Southeastern Coastal Plain aquifer system in parts of eastern Mississippi and western Alabama (No. 1410-G).

[4] Dockery III, D.T. & D.E. Thompson (2019). Mississippi Environmental Geology, 2nd edition, Mississippi Department of Environmental Quality, Office of Geology, 398 pp.

[5] Hale-Erlich, W. S., & Coleman Jr, J. L. (1993). Ouachita-Appalachian juncture: A Paleozoic transpressional zone in the southeastern USA. *AAPG bulletin*, *77*(4), 552-568.

[6] Thomas, W. A. (1977). Evolution of Appalachian-Ouachita salients and recesses from reentrants and promontories in the continental margin. *American Journal of Science*, *277*(10), 1233-1278.

[7] Thomas, W. A. (1988). The Black Warrior basin, *in*. L. Sloss, ed., Sedimentary cover—North American craton, U.S.: Geological Society of America, The Geology of North America, v. D-2, p. 471-491.

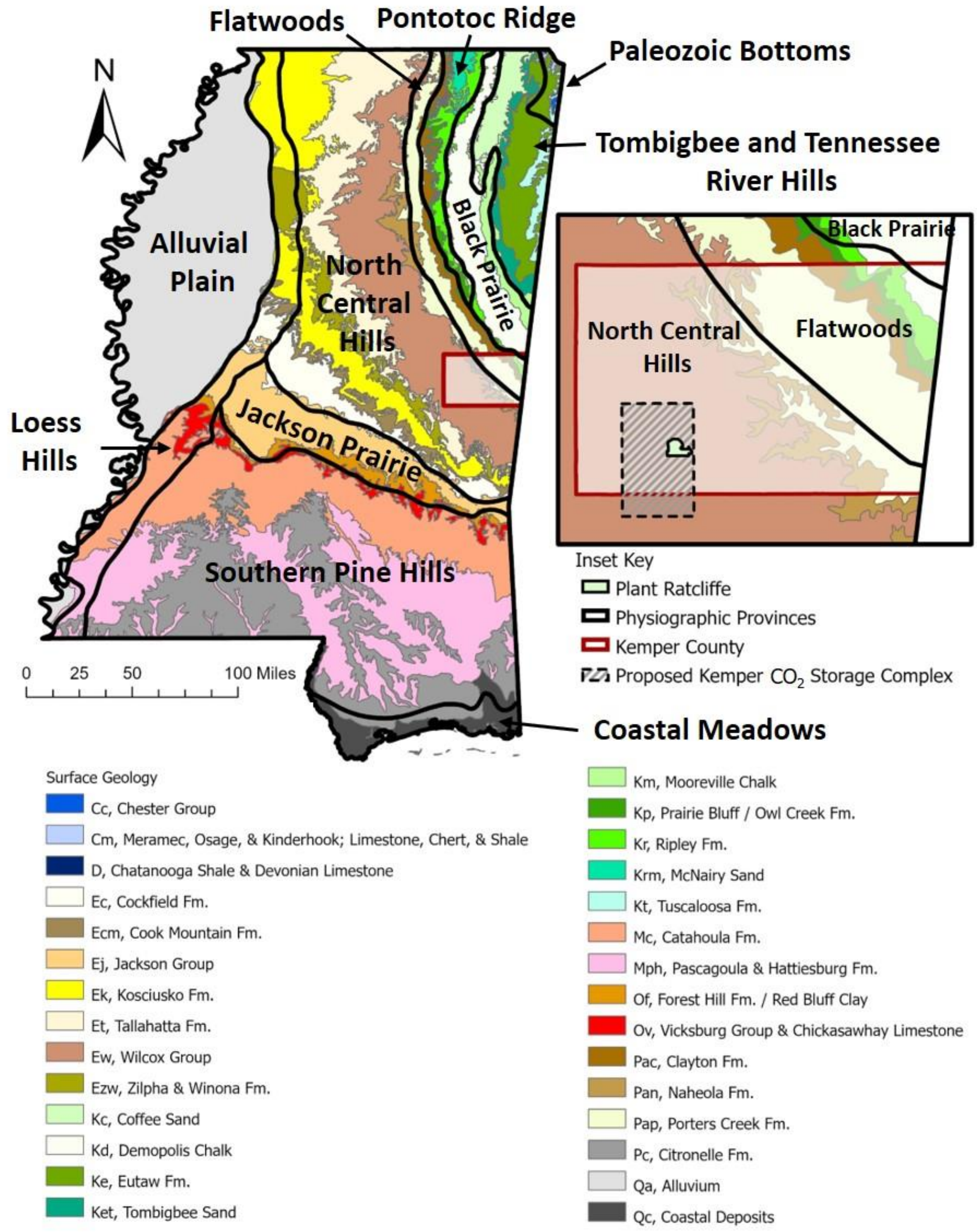

Figure 4. Map of the Surface Geology in Mississippi with Physiographic Regions. Inset map shows the Location of Proposed Kemper County Storage Complex

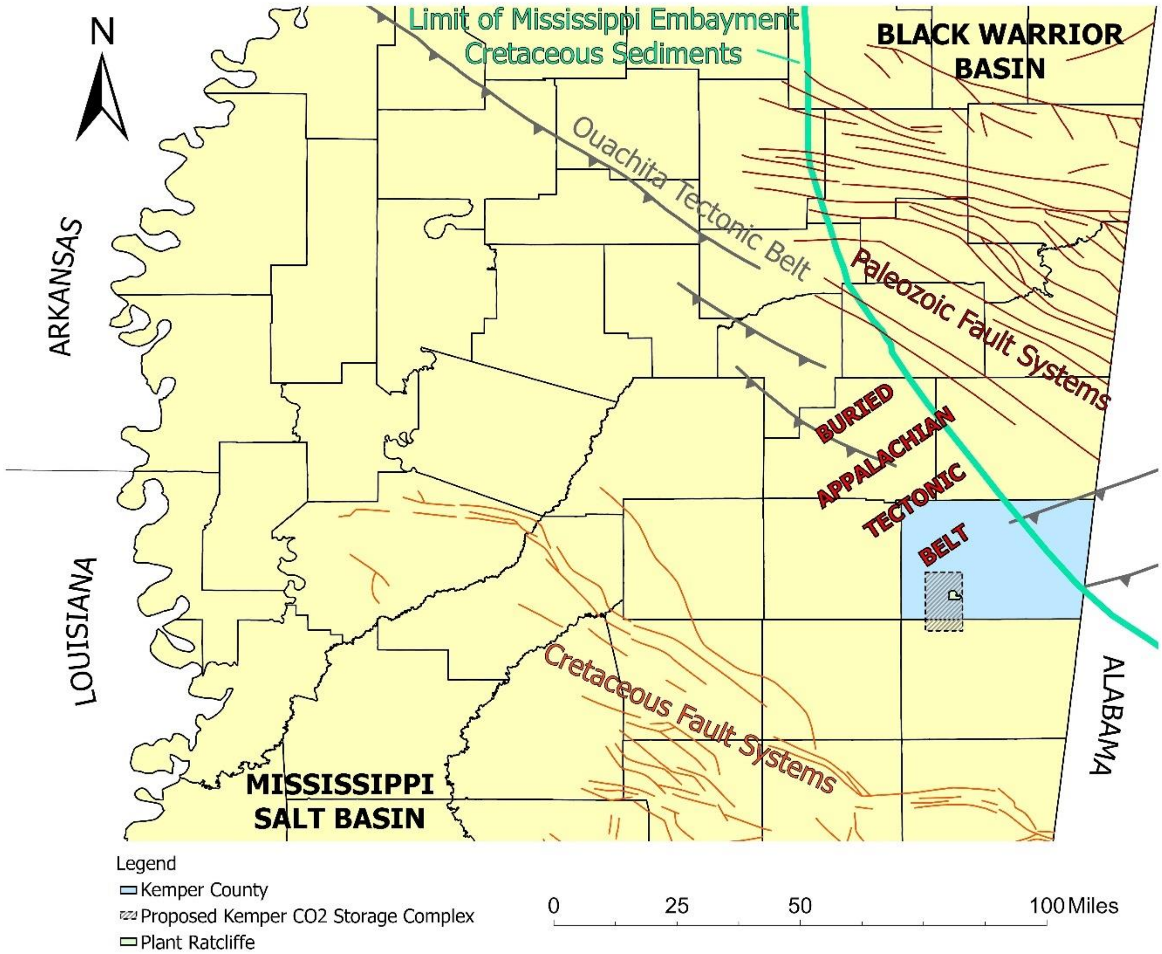

Figure 5. **Generalized Structural Setting of Kemper County Storage Complex in Central Mississippi**

Thrust faults associated with the Appalachian and Ouachita orogenies penetrate the Paleozoic section below the injection zone in Kemper County (**Figure 6**). The transition from the Paleozoic to the Mesozoic is recorded in geophysical logs and seismic lines by an erosional surface marking the change in depositional environment from a synorogenic clastic wedge to fluvial deltaic deposits associated with the Gulf Coastal Plain (**Figure 6)** [8]. Above this unconformity the Mesozoic units are unfaulted and of lower structural complexity (**Figure 7**). The Mesozoic-Cenozoic strata were deposited in the Mississippi Embayment, a subsection of the larger Gulf of Mexico Basin, forming a southwest-dipping wedge of sediment. Mesozoic structural features include the Cretaceous Fault System, located approximately 40 miles south of the Storage

[8] Thomas, W. A. (1985). The Appalachian-Ouachita connection: Paleozoic orogenic belt at the southern margin of North America. *Annual Review of Earth and Planetary Sciences*, *13*(1), 175-199.

Complex, marking the closest surface expression of faults to the Kemper County Storage Complex. The limit of the Cretaceous sediments of the Mississippi Embayment in northeast Kemper County corresponds to the surface outcrop of the Upper Cretaceous age Selma Group.

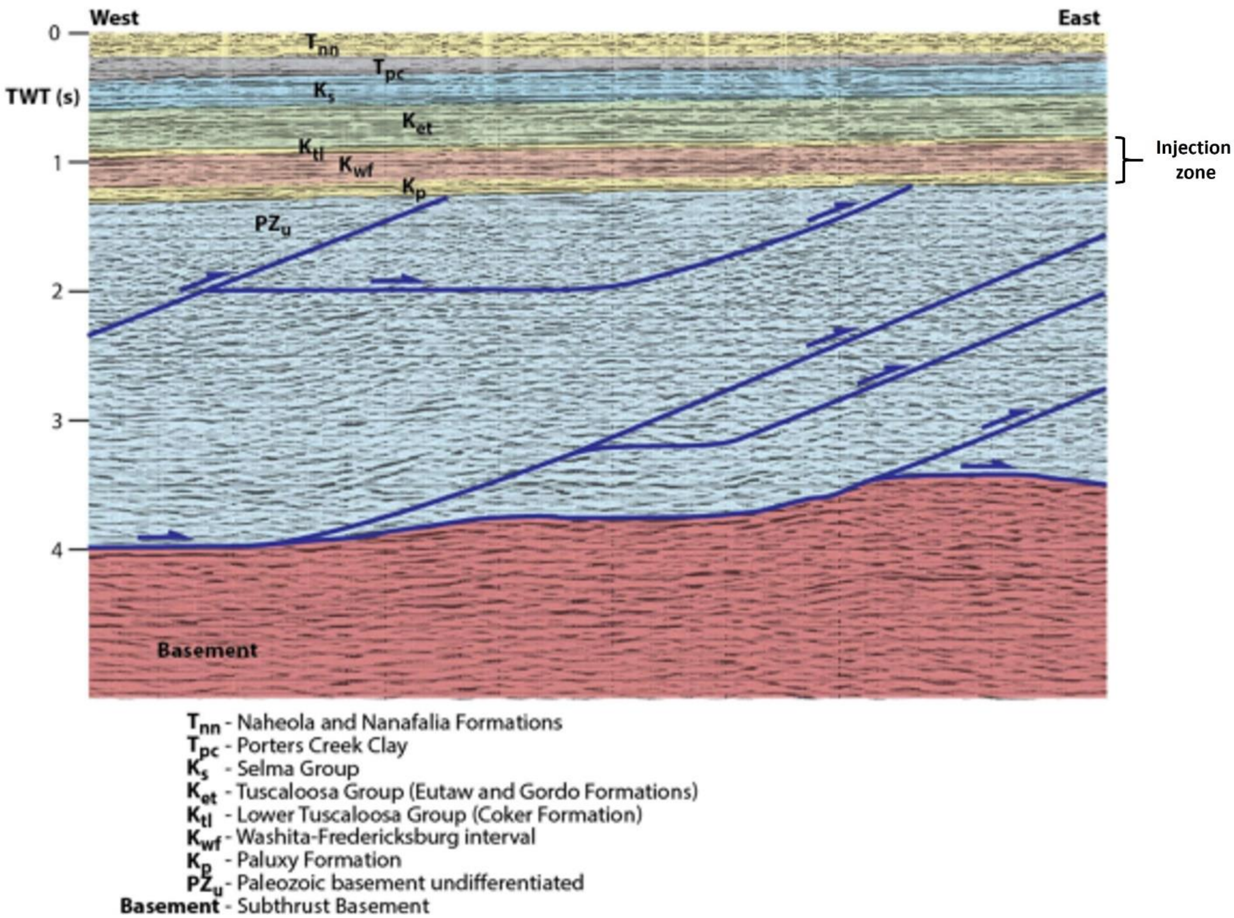

Figure 6. Interpreted Seismic Profile Near the Kemper County County Storage Complex, which shows the relationship between Paleozoic strata of the Appalachian-Ouachita Oregen and gently dipping deposits of the Mississippi Embayment. (Seismic formation licensed to the Geological Survey of Alabama by Seismic Exchange, Incorporated).

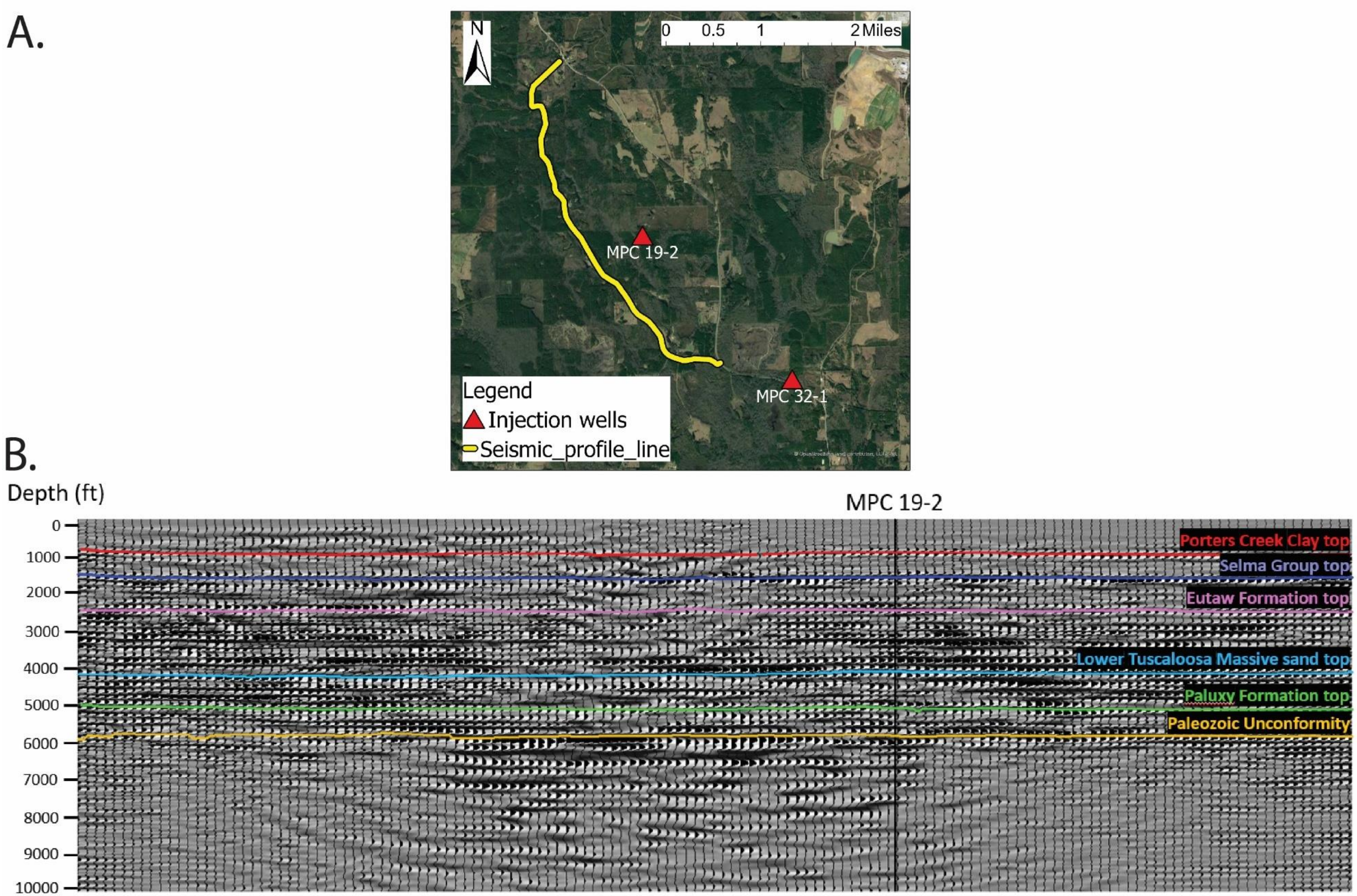

Figure 7. Exoduas 2D Seismic Lines 2021 Survey. A: Map view of seismic profile line relative to proposed injection wells. B: Seismic profile with formation tops and approximate location of MPC 19-2.

B.1.c. Cenozoic and Mesozoic Stratigraphy at the Proposed Kemper County Storage Complex

The thicknesses presented in this section are representative of the six characterization wells (MPC 10-4, MPC 26-5, MPC-34-1, MPC 01-1, MPC 03-1, MPC 19-1) and the Kemper County Storage Complex; see **Section B.2.** for the full description of depths and thicknesses for the target formations.

The shallowest stratigraphic unit at the Kemper County Storage Complex is of Quaternary age (**Table 1**), consisting of Alluvium deposits that serve as the shallowest fresh water bearing aquifer in the county [9]. The underlying Nanafalia Formation of the Wilcox Group consists of 300 ft of sand, clay, and lignite which is underlain by the Nanafalia sand. The sand at the base of the Nanafalia formation is about 200 ft thick and constitutes the primary USDW that is used for drinking water in Kemper County. This Formation includes fluvial, interfluvial, and wetland deposits [10].

The Nanafalia Formation sharply overlies the Naheola Formation of the Paleogene Midway Group. The Naheola Formation is around 110 ft of interbedded, fluvial-deltaic sandstone and shale that becomes more sand-dominated towards the base of the Formation. The Porters Creek Clay consists of 640 ft of gray claystone that coarsens upwards and becomes sandier towards the top of the section where it contacts the overlying Naheola Formation. The Clayton Formation is composed of 20 ft of arenaceous limestone and calcareous sandstone that marks the base of the Midway Group. These strata form a transgressive unit of sediments that blanketed Mississippi Embayment near the beginning of the Paleogene [1110].

The top of the Cretaceous Section in Kemper County is formed by the Selma Group [Error! Bookmark not defined.]. The Selma Group is a 900 ft succession of chalk and marl that represents a regionally extensive muddy carbonate ramp. The combination of the Selma Group along with the Lower Midway Group Clayton Formation and Porters Creek Clay forms a >1,500 ft aquitard that isolates the freshwater-bearing aquifers in the Tertiary from the Cretaceous aquifers below. The Selma Group is underlain by the Eutaw Group, which is a transgressive sedimentary package consisting of 360 ft of marginal marine and shelf deposits [Error! Bookmark not defined.].

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[9] Pashin et al. (2020). See Section A.1., footnote #1

[10] Mancini, E. A., & Tew, B. H. (1993). Eustasy versus subsidence: Lower Paleocene depositional sequences from southern Alabama, eastern Gulf Coastal Plain. *Geological Society of America Bulletin*, *105*(1), 3-17.

[11] Mancini, E. A., Puckett, T. M., & Tew, B. H. (1996). Integrated biostratigraphic and sequence stratigraphic framework for Upper Cretaceous strata of the eastern Gulf Coastal Plain, USA. *Cretaceous Research*, *17*(6), 645-669.

Table 1. Cenozoic and Mesozoic Stratigraphic Units at Proposed Kemper County Storage Complex.

System		Series		Stratigraphic Unit	Major Sub-Units	Potential Reservoirs and Confining Units	
Quaternary		**Holocene**		Alluvium		Shallow Alluvial Aquifers	
Tertiary	**Paleogene**	**Eocene**	**Lower**	Wilcox Group	*Undifferentiated*	Freshwater Aquifer	
		Paleocene	**Upper**		Nanafalia Fm.		
				Midway Group	Naheola Fm.	Freshwater Aquifer	
					Porters Creek Clay	Aquitard	
			Lower		Clayton Fm.		
Cretaceous		**Upper**		Selma Group	Owl Creek / Prairie Bluff Fm.	Aquitard	
					Ripley (McNairy) Fm.		
					Demopolis Fm.		
					Mooreville Fm.		
				Eutaw Group	Tombigbee Sand	USDW	
					McShann Fm.		
				Tuscaloosa Group	Upper Tuscaloosa (Gordo Fm.)	USDW	
					Tuscaloosa Marine Shale	**Confining zone**	
					Undifferentiated Lower Tuscaloosa Shale		
					Lower Tuscaloosa Massive Sand	**Saline Reservoir**	**INJECTION ZONE**
		Lower		Washita-Fredericksburg	Dantzler Fm.	**Saline Reservoir**	
					Undifferentiated Upper Shale	**Confinement Interval**	
					'Big Fred' Sand	**Saline Reservoir**	
					Undifferentiated Basal Shale	**Confinement Interval**	
				Paluxy Formation		**Injection Interval**	
				Mooringsport Formation		Limestone Marker	
Paleozoic Undifferentiated				Pennsylvanian Pottsville Fm?		Regional Confining Unit	

The Tuscaloosa Group is divided into the Upper Tuscaloosa, the Tuscaloosa Marine shale, and the Lower Tuscaloosa [12]. The Upper Tuscaloosa consists of a 280 ft thick coarsening-upwards succession of thickly interbedded sandstone and variegated mudstone. The Tuscaloosa Marine shale is a 220 - 250 ft thick succession of interbedded shale, siltstone, and fine-grained sandstone that grades upwards from offshore facies to coastal and terrestrial facies in the overlying Upper Tuscaloosa. The Lower Tuscaloosa consists of the undifferentiated shale which makes up the upper 240 - 320 ft of the Formation, and the Massive sand. The Massive sand member is a 200 - 240 ft interval of very fine- to medium-grained sands. A basal conglomerate forms the lower 30 - 50 ft of the Massive sand, and the remainder is dominated by very poorly consolidated sandstone. The sand is interpreted to have formed in a fluvial to coastal setting [12].

The Washita-Fredericksburg interval is composed of two primary stratigraphic units, the sandstone lithofacies and the mudstone lithofacies. The sandstone lithofacies consists of the Dantzler and “Big Fred” sand members, while the mudstone lithofacies consists of the Upper and Basal Washita-Fredericksburg shale units. The Dantzler Formation forms the upper 50 – 120 ft of the Washita-Fredericksburg interval and is composed of multi-storied sandstone bodies separated by mudstone intervals that are around 10 ft thick [13]. The Upper Washita-Fredericksburg shale is 310 - 400 ft and consists of interbredded sandstone and mudstone layers that is dominantly shaly, with individual mudstone packages typically < 35 ft [13]. The “Big Fred” sand makes up the central portion of the Washita-Fredericksburg interval and consists of a 410 - 490 ft thick succession of quartzose sandstone, pebble and cobble conglomerate and red and gray mottled mudstone [14]. Individual sandstone bodies are up to 100 ft thick, and as mudstone decreases upwards in section, single-story sandstone bodies are locally thicker than 60 ft with varying lateral continuity [15]. Like the Upper Washita-Fredericksburg shale, the Basal shale consists mostly of shale with some sandstone interbeds and is around 310 - 400 ft thick. The

[12] Mancini, E. A., Mink, R. M., Wayne Payton, J., & Bearden, B. L. (1987). Environments of deposition and petroleum geology of Tuscaloosa Group (Upper Cretaceous), South Carlton and Pollard fields, southwestern Alabama. *AAPG Bulletin*, *71*(10), 1128-1142.

[13] Pashin et al. (2020). See Section A.1., footnote #1.

[14] Pashin, J. C., Hills, D. J., Kopaska-Merkel, D. C., & McIntyre, M. R. (2008). Geological Evaluation of the Potential for CO2 Sequestration in Kemper County. *Mississippi: Birmingham, Final Report, Southern Company Research & Environmental Affairs*.

[15] Koperna, G. (2020). *Geologic Framework for the Kemper Storage Complex (Deliverable 6.2. b)* (No. DOE-SSEB-0029465-54). Southern States Energy Board, Peachtree Corners, GA (United States).

Washita-Fredericksburg interval was deposited in a fluvial environment, likely representing interfluvial redbeds [14 16].

The Paluxy Formation consist of a 530 - 630 ft interval of fine- to medium-grained sandstone, conglomerate, and mudstone that are arranged in thickly bedded packages with cross-bedding structures. Sandstone beds are 10 - 100 ft thick and about 40 ft on average, whereas mudstone interbeds are usually less than 20 ft. The Paluxy sands are interpreted to have been deposited in the in a fluvial setting similar to the Washita-Fredericksburg interval [17]. The lowest Mesozoic stratigraphic unit above the Paleozoic unconformity is the Moorinsport Formation, which is a subhorizontal limestone interval that is 30 - 60 ft thick.

B.1.d. Storage zone

The target storage and confining formations at the Kemper County Storage Complex are in the Lower Cretaceous section of Kemper County, from the top of the Tuscaloosa Marine shale to the base of the Paluxy Formation (**Table 1**). These identified zones are known to be regionally consistent throughout eastern Mississippi. The Primary confining zone for this Project is the Tuscaloosa Marine shale and undifferentiated Lower Tuscaloosa shale, which will be referred to as the Tuscaloosa Marine shale confining zone. Locally, the Marine shale isolates USDWs in the Upper Tuscaloosa and Eutaw Formations from saline aquifers in the Lower Tuscaloosa Massive sand and Dantzler sandstone. The Tuscaloosa Marine shale is a proven confining unit in Mississippi and Alabama for hydrocarbons in the Lower Tuscaloosa [18 19 20]. Below the confining zone is the injection zone, which consists of a series of saline storage zones, confinement intervals, and the injection interval. The Paluxy Formation is the base of the injection zone and serves as the specific injection interval for this Project. The Massive sand, Dantzler Formation, and ‘Big Fred’ sand are alternate saline storage reservoirs in the injection zone, while the Upper and Basal Washita-Fredericksburg shales are secondary confinement intervals. The confinement intervals and alternate saline storage reservoirs form a containment system that can buffer the vertical migration of fluids out of the injection interval, with the Tuscaloosa Marine shale confining

[16] Renken, R. A., Mahon, G. L., & Davis, M. E. (1989). Hydrogeology of clastic Tertiary and Cretaceous regional aquifers and confining units of the southeastern coastal plain aquifer system of the United States (No. 701)

[17] Folaranmi, A. T. (2015). *Geologic characterization of a saline reservoir for carbon sequestration: The Paluxy Formation, Citronelle Dome, Gulf of Mexico Basin, Alabama* (Doctoral dissertation).

[18] Galicki, S. J. (1986). Frontmatter: Mesozoic-Paleozoic Producing Areas of Mississippi and Alabama.

[19] Mancini et al. (1987) See Section B.1.c., footnote #12.

[20] Bebout, D. G., White, C. M., Garrett, C. M., and Hentz, T. F., editors (1992). Atlas of major central and eastern Gulf Coast gas reservoirs: Austin, Texas, Gas Research Institute and Texas Bureau of Economic Geology, 88 p.

zone providing the ultimate closure for this system. See **Section B.2.** for full dataset of injection and confining zone depths and thicknesses in the project area.

Figure 8 is a composite type-log showing of the typical depths and thicknesses of the Tertiary and Cretaceous age formations. The shallow Tertiary formations and the Upper Cretaceous Selma Group are represented by the Southern Company #1 water test well, located at Plant Ratcliffe, while the deeper Cretaceous formations below the Selma Group are represented by the MPC 19-1 well. The logs are representative of the geology of the Kemper County Storage Complex, specifically focused around Plant Ratcliffe.

B.1.e. Hydrogeology

The USDW aquifers within Kemper County reside in both Tertiary- and Upper Cretaceous-age clastic reservoirs. The Tertiary formations include the Middle and Lower Wilcox, the Naheola, and the Nanafalia Formations (**Table 1**). The Middle and Lower Wilcox USDW aquifers have Total Dissolved Solids (TDS) of < 200 milligrams-per-liter (mg/L). The principal drinking water source for Kemper County comes from the Middle and Lower Wilcox Formation. Potable water at Plant Ratcliffe is provided by the Northwest Kemper Water Association which utilizes the Lower Wilcox as its source for drinking water. The Naheola and Nanafalia Formations are shallower than 600 feet in the area around the Storage Complex, and these formations receive meteoric recharge at the surface in northeastern Kemper County. Therefore, all active and potential aquifers of Tertiary age can be expected to be USDWs and must be protected. The Porters Creek clay and Selma Group together serve as an aquitard to separate the freshwater aquifers in the Tertiary from the Upper Cretaceous. The Upper Cretaceous contains the Eutaw-McShan, Gordo and Coker with potential USDW aquifers with TDS concentrations of 1,000 to 20,000 mg/L. The Eutaw-McShan aquifer is the deepest USDW in the Kemper County Storage Complex. Water used for industrial purposes at Plant Ratcliffe (i.e., nonpotable) is sourced primarily as reclaimed water from two publicly owned treatment works (POTWs) nearby and is thus not related to USDWs. All reservoirs that qualify as USDWs will be monitored in the region for signs of contamination. The most likely indicators of groundwater impact from CO_2 leakage include: 1) an increase in TDS content if water with higher TDS migrated into overlying USDW and 2) a reduction in pH as CO_2 or carbonated brine results in an increase in dissolved carbonate or bicarbonate. See **Section B.7.** for more on the hydrogeology of the Kemper County Storage Complex.

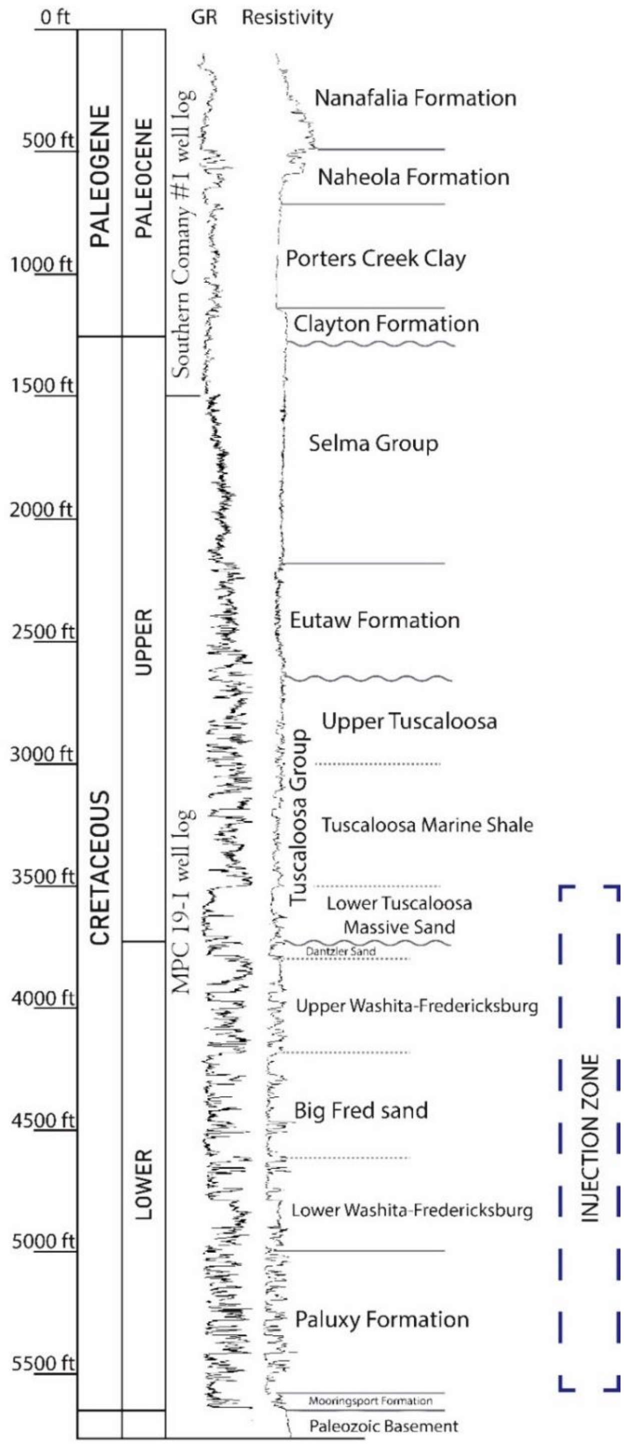

Figure 8. Composite "Type" Log, for Mesozoic-Cenozoic Formations at the Proposed Kemper County Storage Complex. GR = Gamma Ray. Each log is showing increasing values from left to right.

B.2. Maps and Cross Sections of the AoR [40 CFR 146.82(a)(2), 146.82(a)(3)(i)]

Figure 9 shows the full Stratigraphic cross section for the six characterization wells. The cross section was generated in Petra™ by selecting formation tops using geophysical logs from the top of section to TD (total depth). Gamma ray values are colored from left to right to relatively distinguish sandstone or limestone units corresponding to low API (beige), from shaly sequences corresponding to higher API (black). The Maximum Flooding Surface in the Tuscaloosa Marine shale interval serves as the reference datum. Interpretation of the characterization wells shows a uniform stratigraphic package across our interval of interest. No significant changes in formation thickness have been observed through the characterization wells and the primary confining interval shows no sign of diminishing across the project area. The storage interval (Massive sand through base of Paluxy) represents a 2000 – 2200 ft thick package over the study area.

Figure 10 is an enhanced cross-section of the characterization wells, showing the primary confining zone (Tuscaloosa Marine shale) and storage interval (top Massive through base Paluxy Formation), which includes the Upper and Basal shales of the Washita-Fredericksburg group as secondary confinement intervals. Log analysis of the characterization wells indicates that the geology of the proposed storage and confining interval is consistent across the area of review. Characterization of the Paluxy Formation has identified four zones as potential CO_2 storage reservoirs. These zones consist of sand bodies that are separated by shale baffles which will control the movement of the CO_2 plume in the subsurface. See the *Area of Review and Corrective Action Plan* for more information about the modelled CO_2 plume.

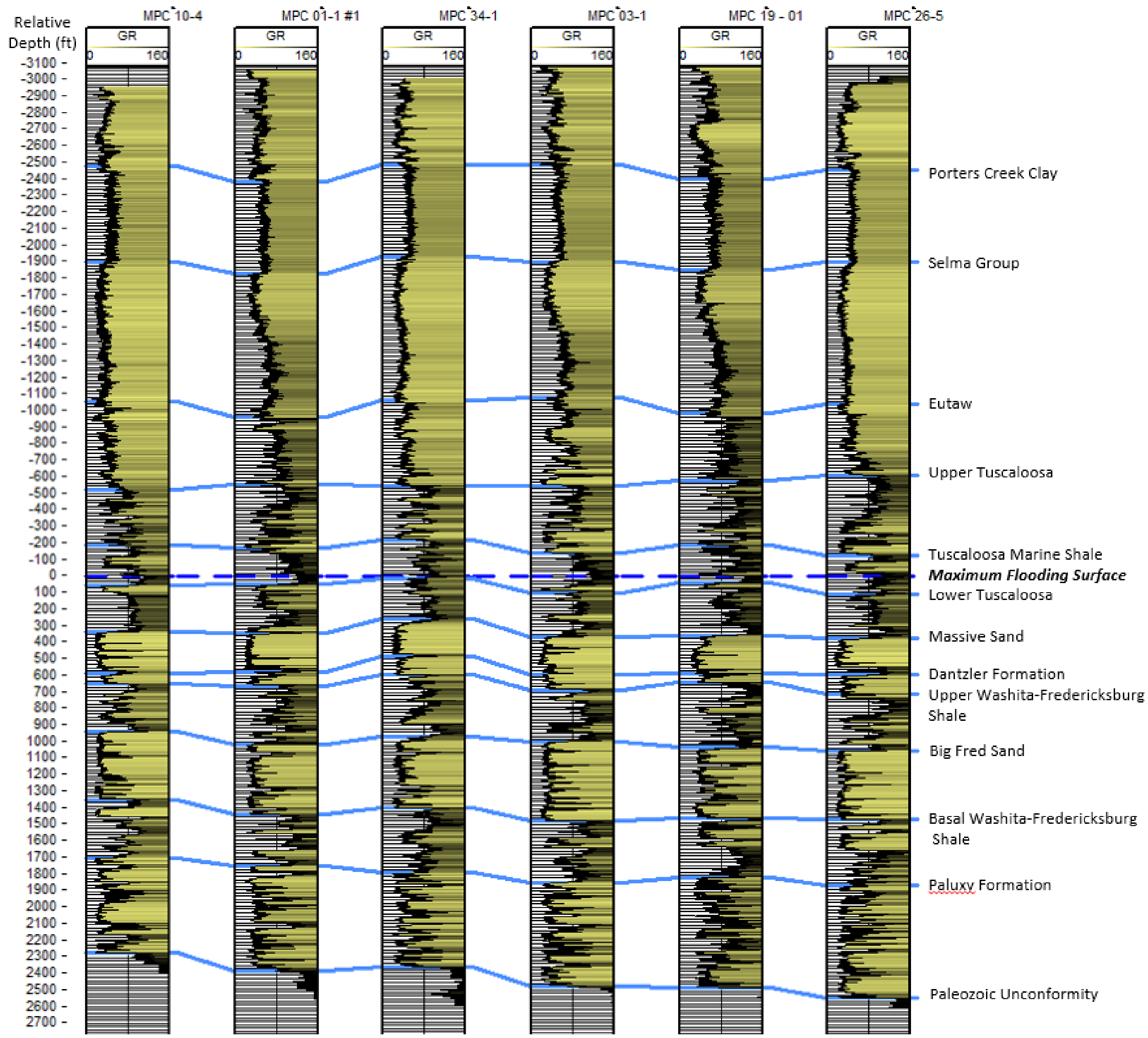

Figure 9. Characterization Wells Full cross-section. The cross-section is flattened on the Maximum Flooding Surface in the Tuscaloosa Marine Shale interval.

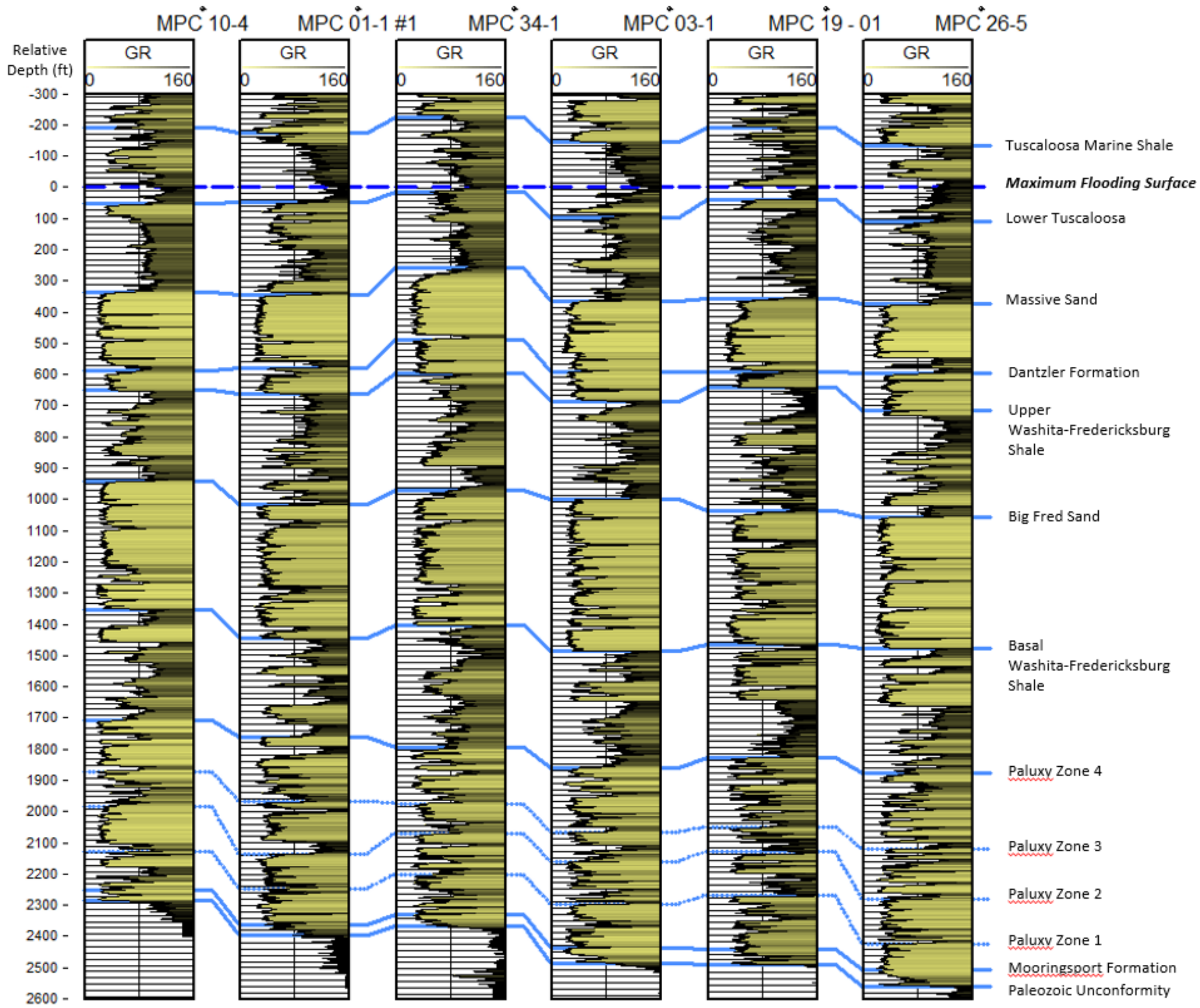

Figure 10. Characterization Well Cross-section of the Injection Zone. Gamma ray (API) is in track 1, and resistivity (Ohm-meter) is in track 2 for each well. The cross-section is flattened on the Maximum Flooding Surface in the Tuscaloosa Marine Shale interval.

As part of the characterization process, stratigraphic picks were made on the digital well logs through the use of the Petra™ geologic interpretation software suite. These logs were then correlated across the study area resulting in a series of contour and isopach maps to demonstrate the relative structure and thickness of the injection zone, storage interval, and primary and secondary confining zones. All depths are reported in feet sub-sea (SS). **Figure 11** shows the spatial extent of the contour maps, using the characterization wells as a point of reference, marking the approximate location of the injection wells. Each of the confinement intervals and storage zones are laterally continuous across this region and there are no major geologic structures (faults, domes, etc.) in the storage zone that would serve as trapping mechanisms or leakage pathways for stored CO_2 and/or brine to escape toward the ground surface. The red dashed line shown is the official Area of Review (AoR) that was modelled for the Kemper County Storage Complex. For more information on the spatial extent of the AoR, see the *Area of Review and Corrective Action Plan*.

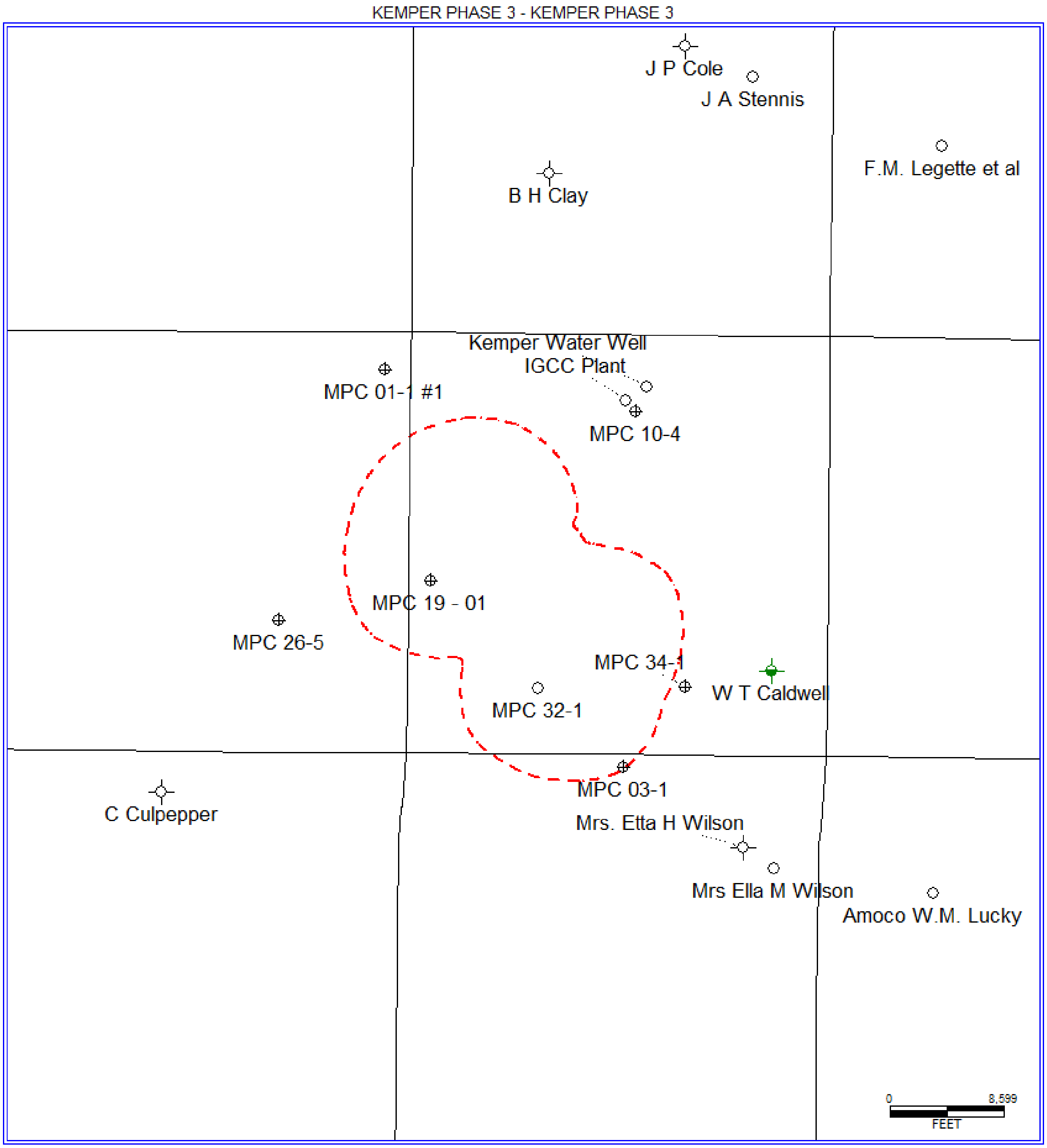

Figure 11. Contour Map Data Limits, including well locations, well names, and the Area of Review outline (red dashed line).

The elevation of the Tuscaloosa Marine shale is -2692 to - 2380 ft SS around the characterization wells (**Figure 12)**, and the thickness of the Marine shale ranges from 221 - 245 ft (**Figure 13)**. The Marine shale dips to the southwest at 59.2 ft per mile and thickens towards the south of the characterization wells from 219 – 245 ft.

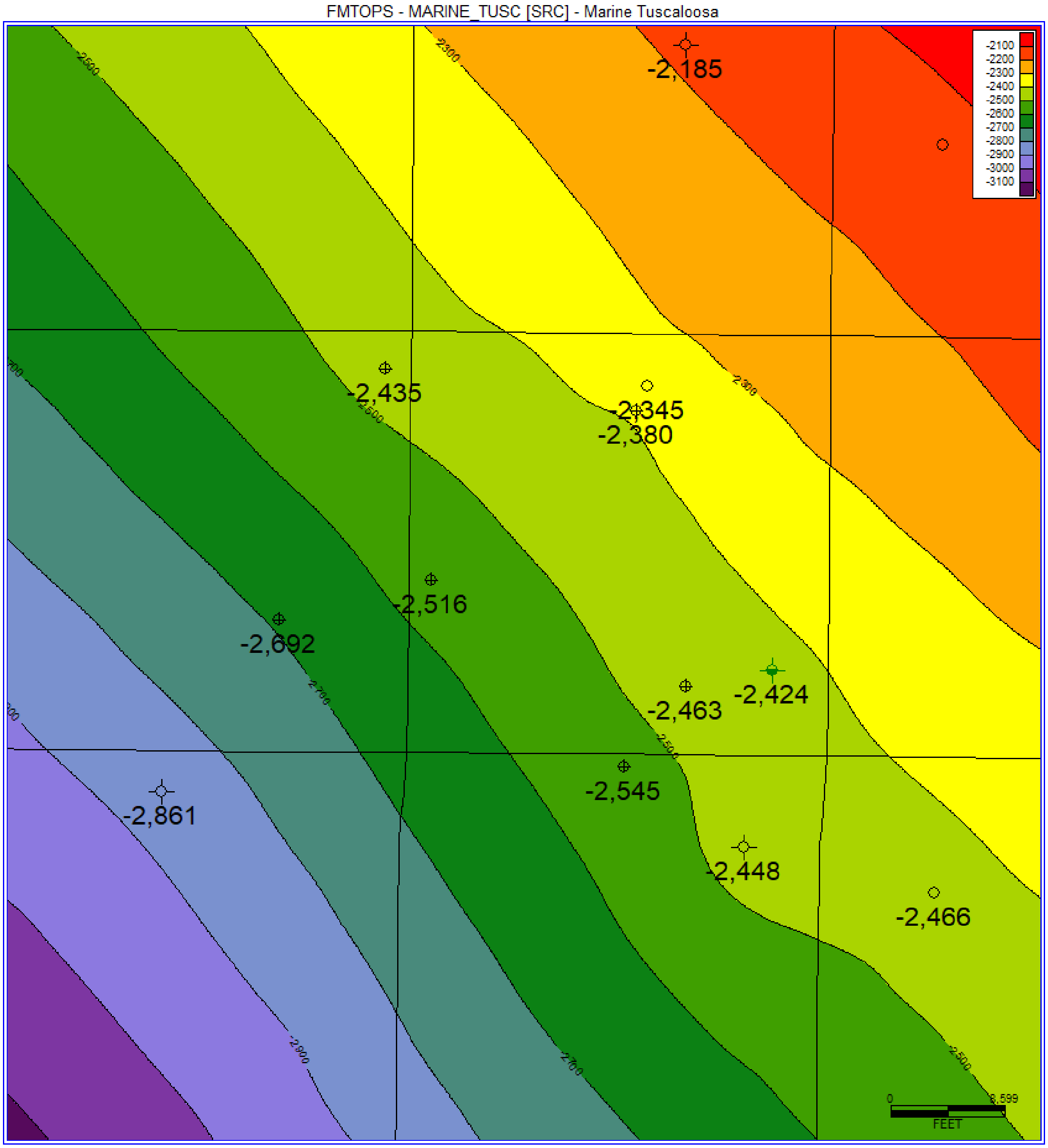

Figure 12. Top of Tuscaloosa Marine Shale Structure Map

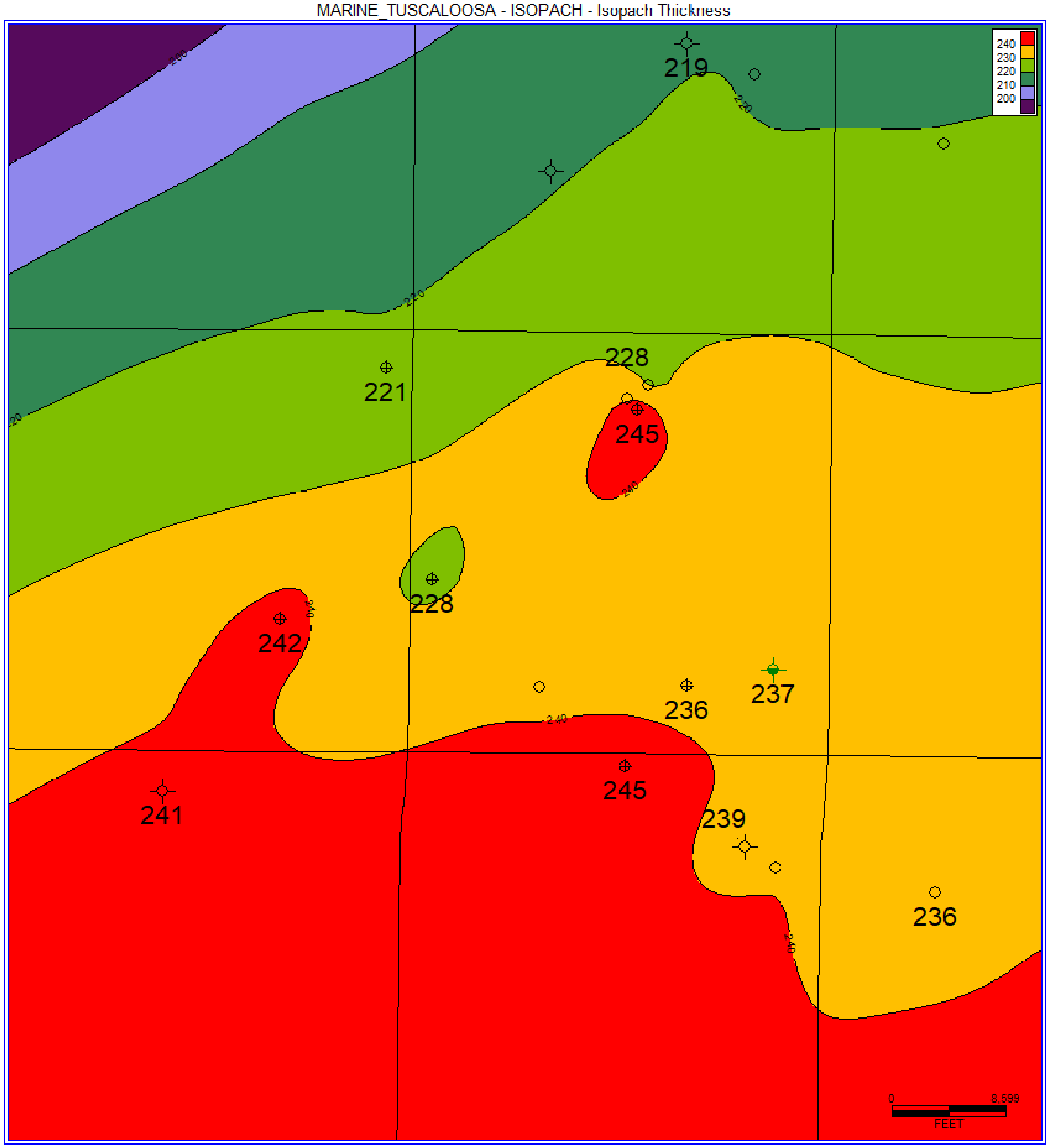

Figure 13. Tuscaloosa Marine Shale Gross Isopach Map

The elevation of the Lower Tuscaloosa is -2934 to - 2625 ft SS around the characterization wells (**Figure 14)**, and the thickness ranges from 245 - 319 ft (**Figure 15)**. The Lower Tuscaloosa dips to the southwest at 54.9 ft per mile and its thickness nonuniformly decreases to the northeast and southwest of the characterization wells. The net shale of the Marine shale and Lower Tuscaloosa shale ranges from 236 – 267 ft in the characterization wells (**Figure 16**).

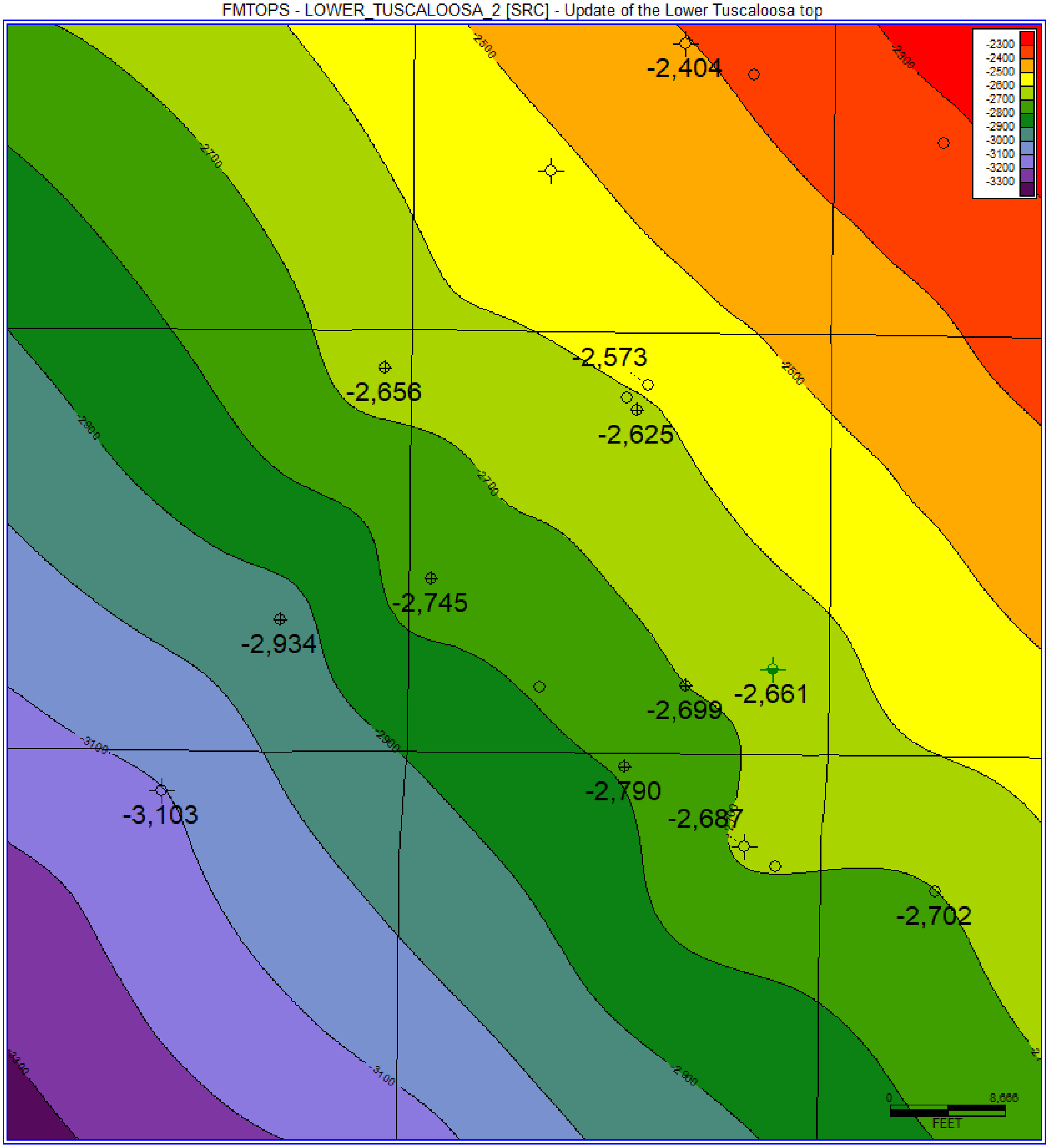

Figure 14. Top of Lower Tuscaloosa shale Structure Map

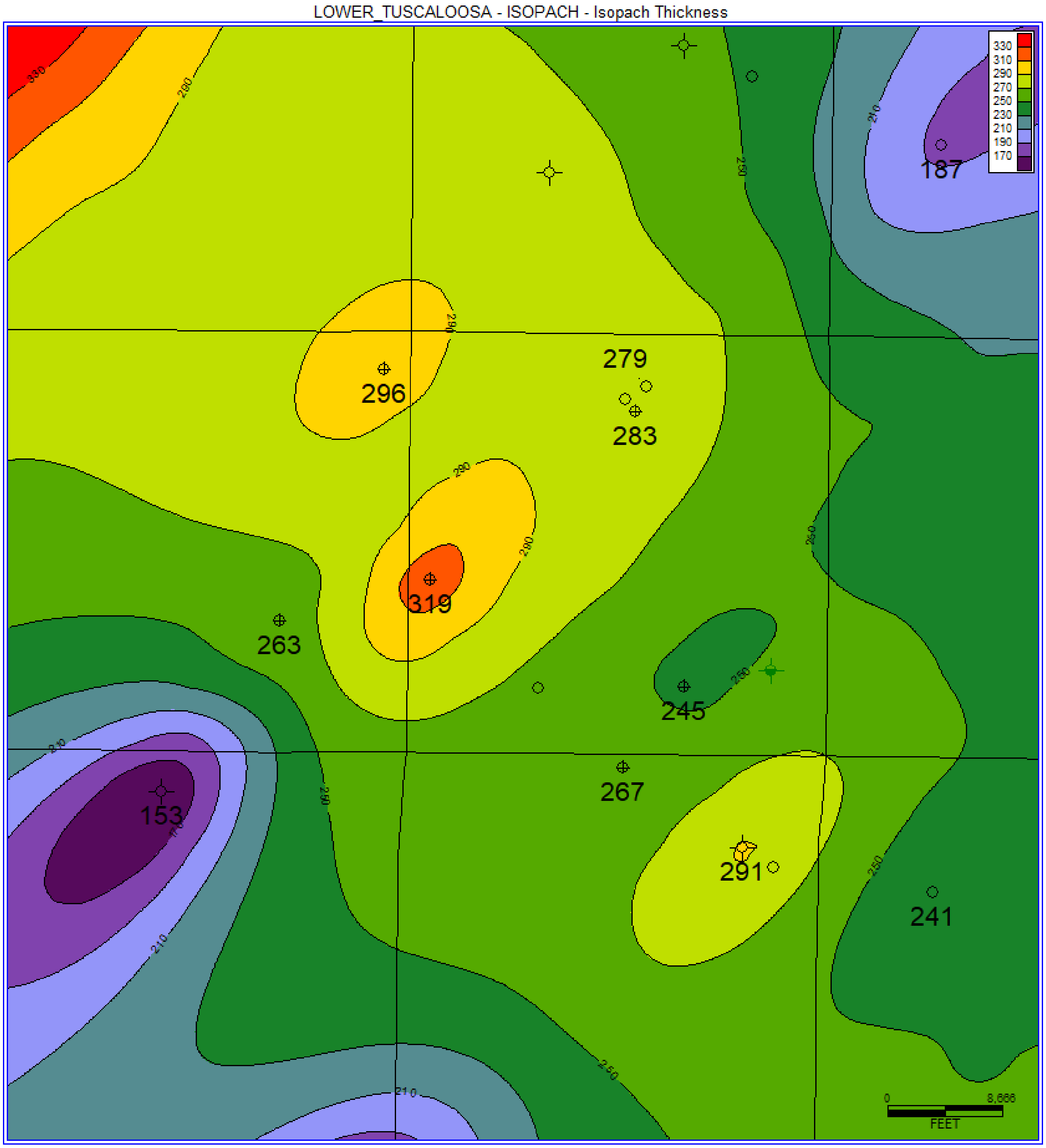

Figure 15. Lower Tuscaloosa Gross Isopach map

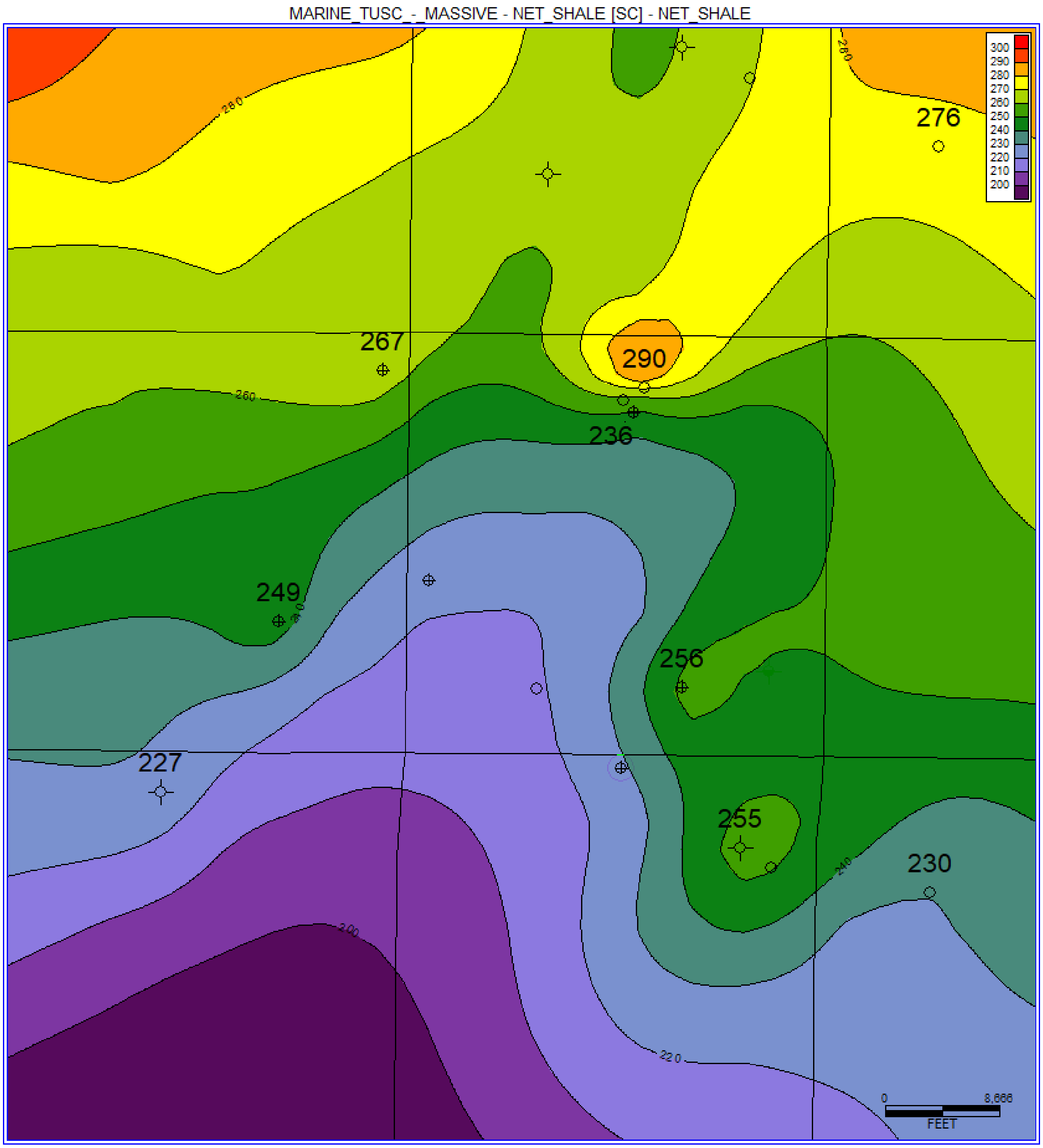

Figure 16. Net shale map (ft) of the interval from the top of the Tuscaloosa Marine Shale to the top of the Massive sand.

The depth of the Massive sand is - 3197 to - 2909 ft SS around the characterization wells (**Figure 17**), and the thickness ranges from 201 to 232 ft (**Figure 18**). The Massive sand dips towards the southwest at 43.2 ft per mile, and thickens nonuniformly to the southeast.

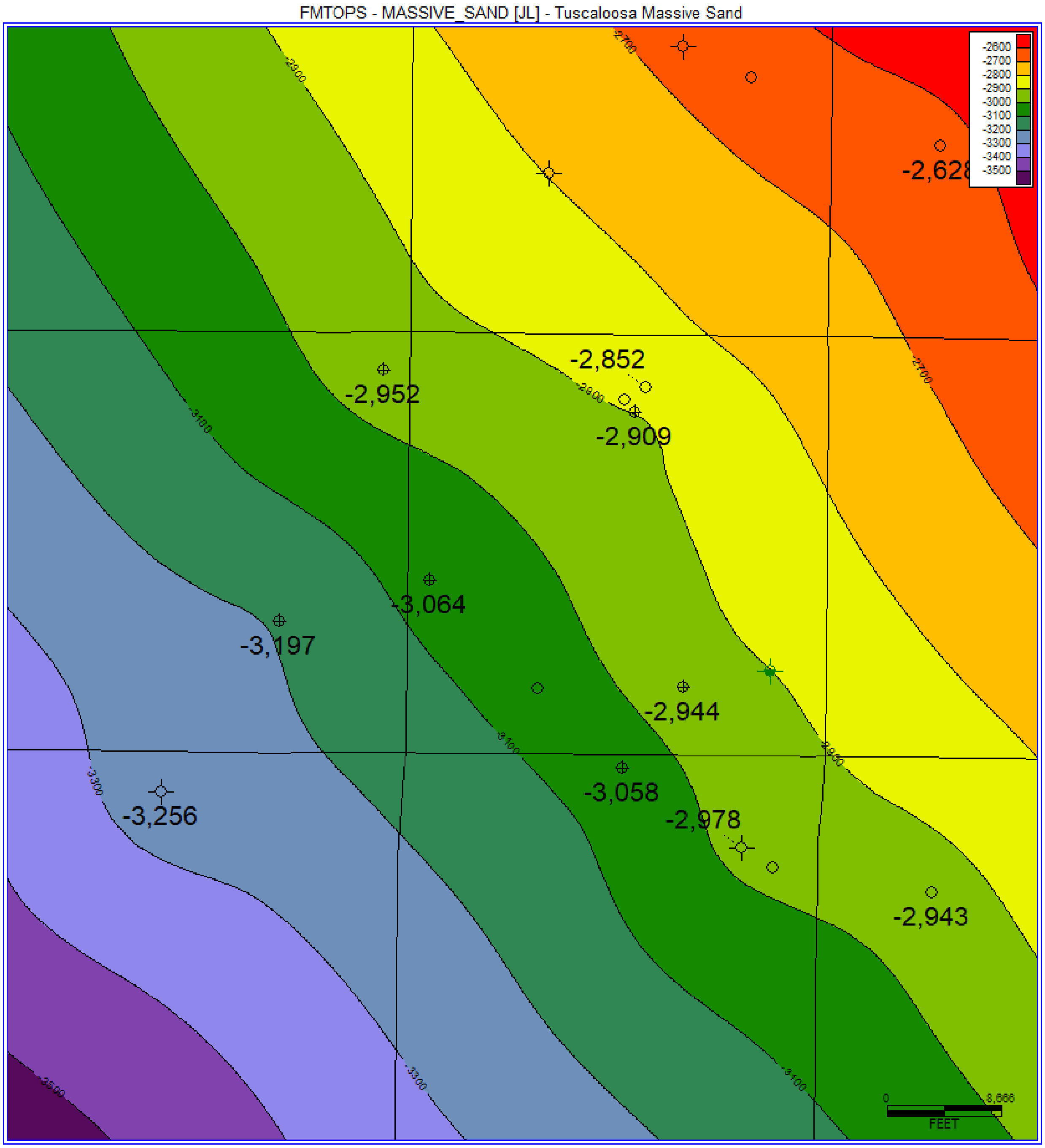

Figure 17. Top of Massive Sand Structure Map

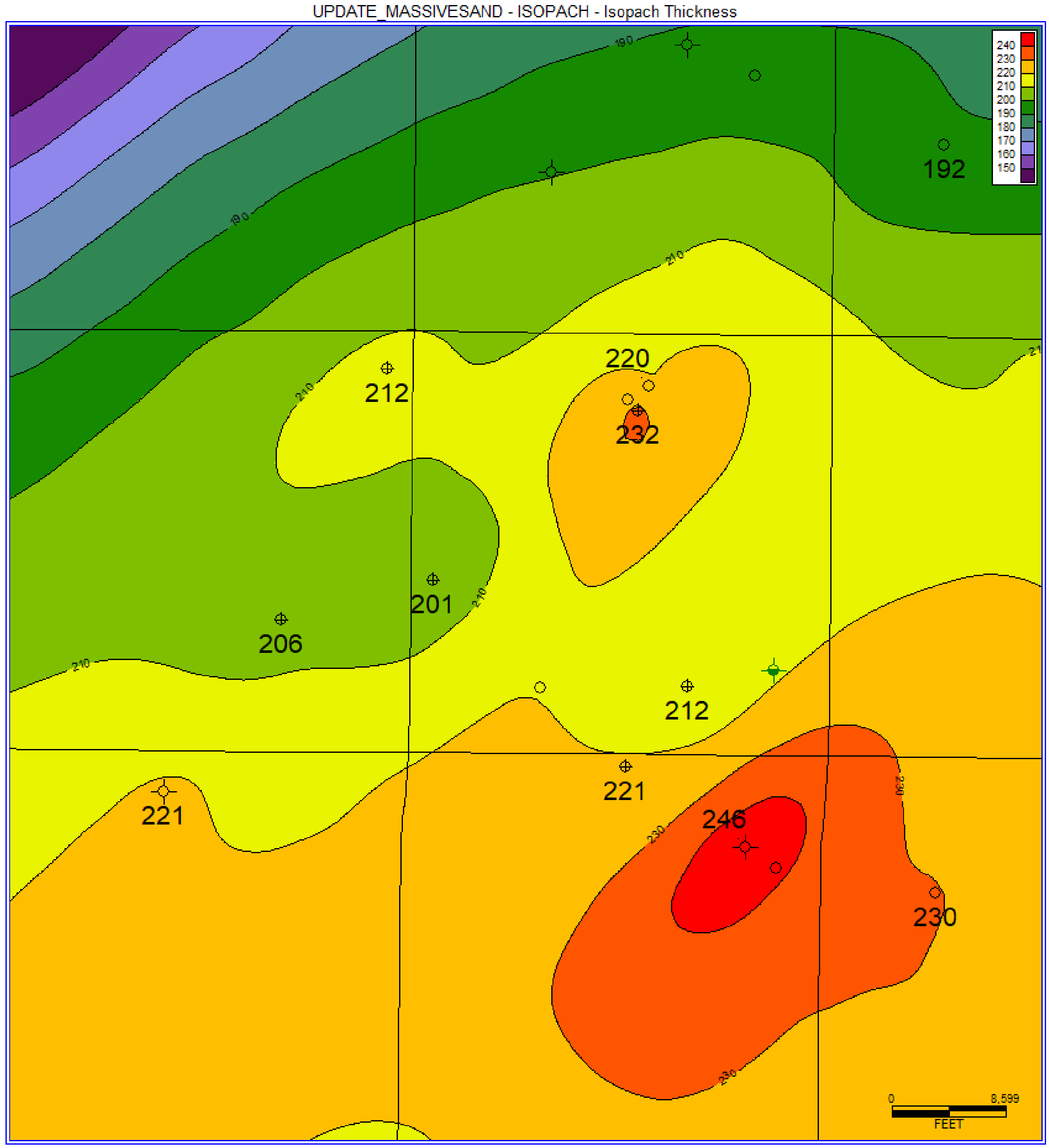

Figure 18. Massive Sand Gross Isopach Map

The elevation of the Dantzler Formation is -3419 to - 3159 ft SS around the characterization wells (**Figure 19)**, and the thickness ranges from 52 - 119 ft (**Figure 20)**. The Dantzler dips to the southwest at 45 ft per mile and its thickness increases to the southwest of the characterization wells from <52 ft to 182 ft.

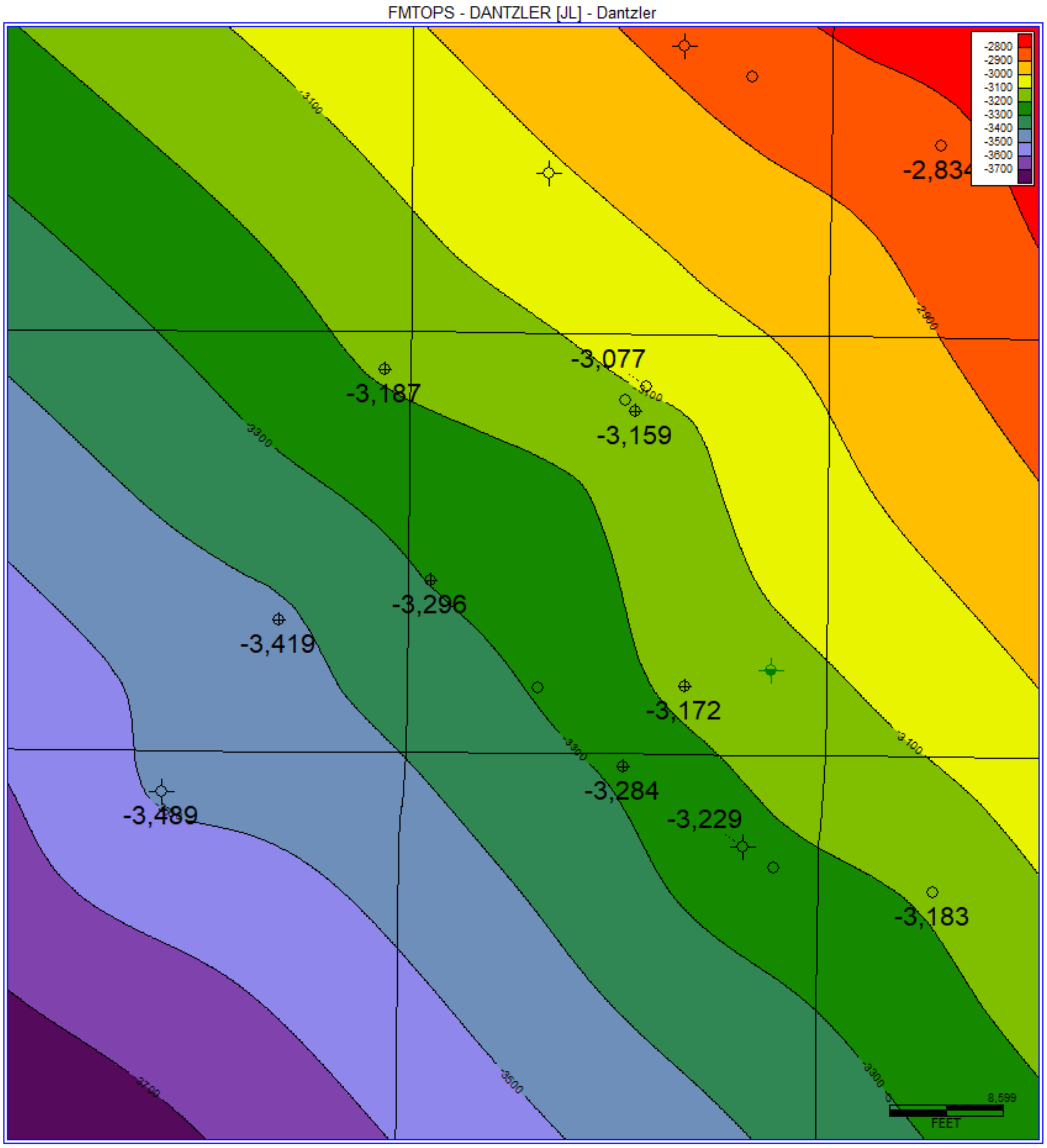

Figure 19. **Dantzler Formation Structure Map**

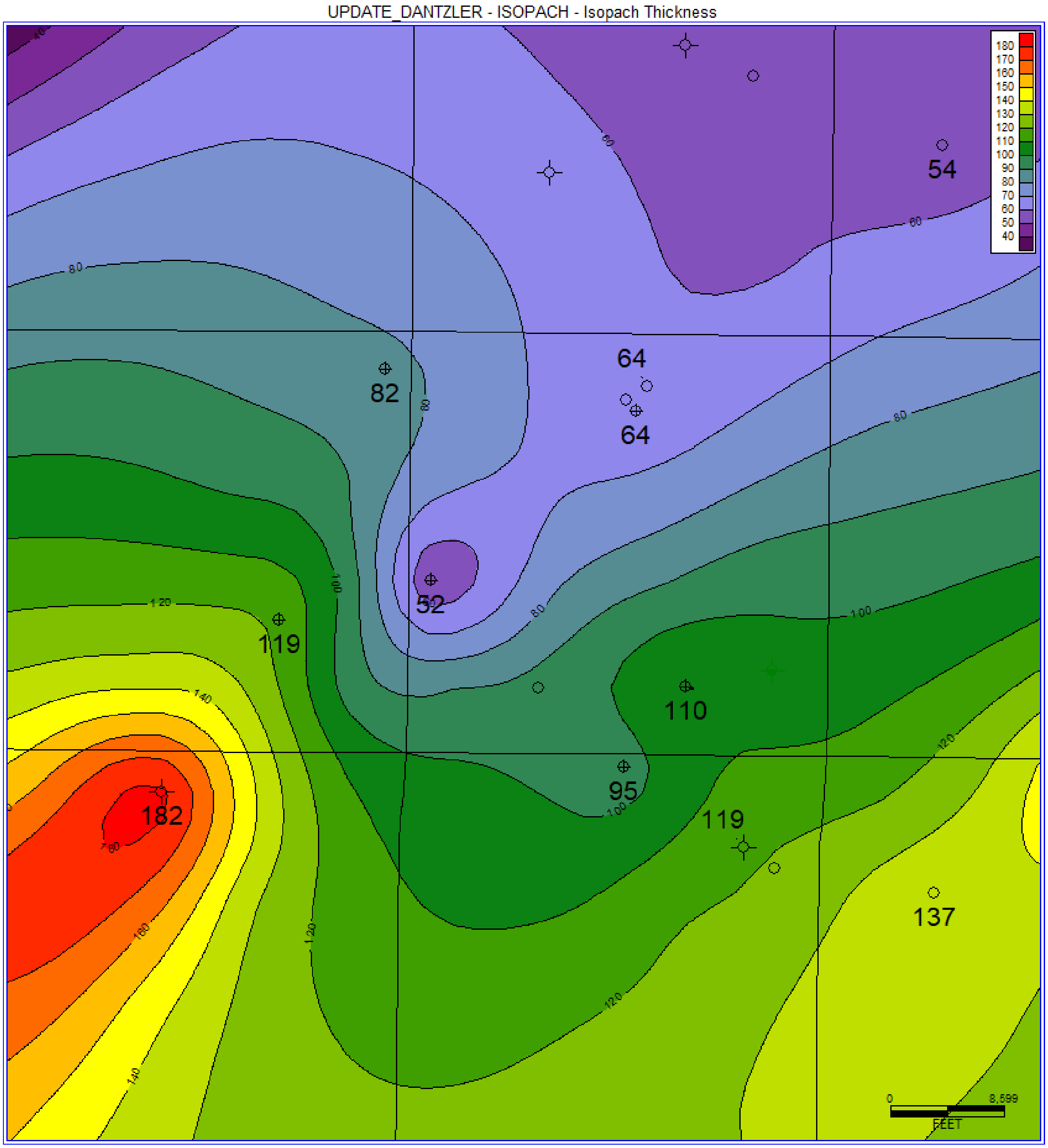

Figure 20. Dantzler Formation Gross Isopach Map

The elevation of the Upper Washita-Fredericksburg shale is -3538 to - 2625 ft SS around the characterization wells (**Figure 21)**, and the thickness ranges from 289 - 396 ft (**Figure 22)**. The Upper Washita-Fredericksburg dips to the southwest at 53.8 ft per mile and its thickness increases to the northeast.

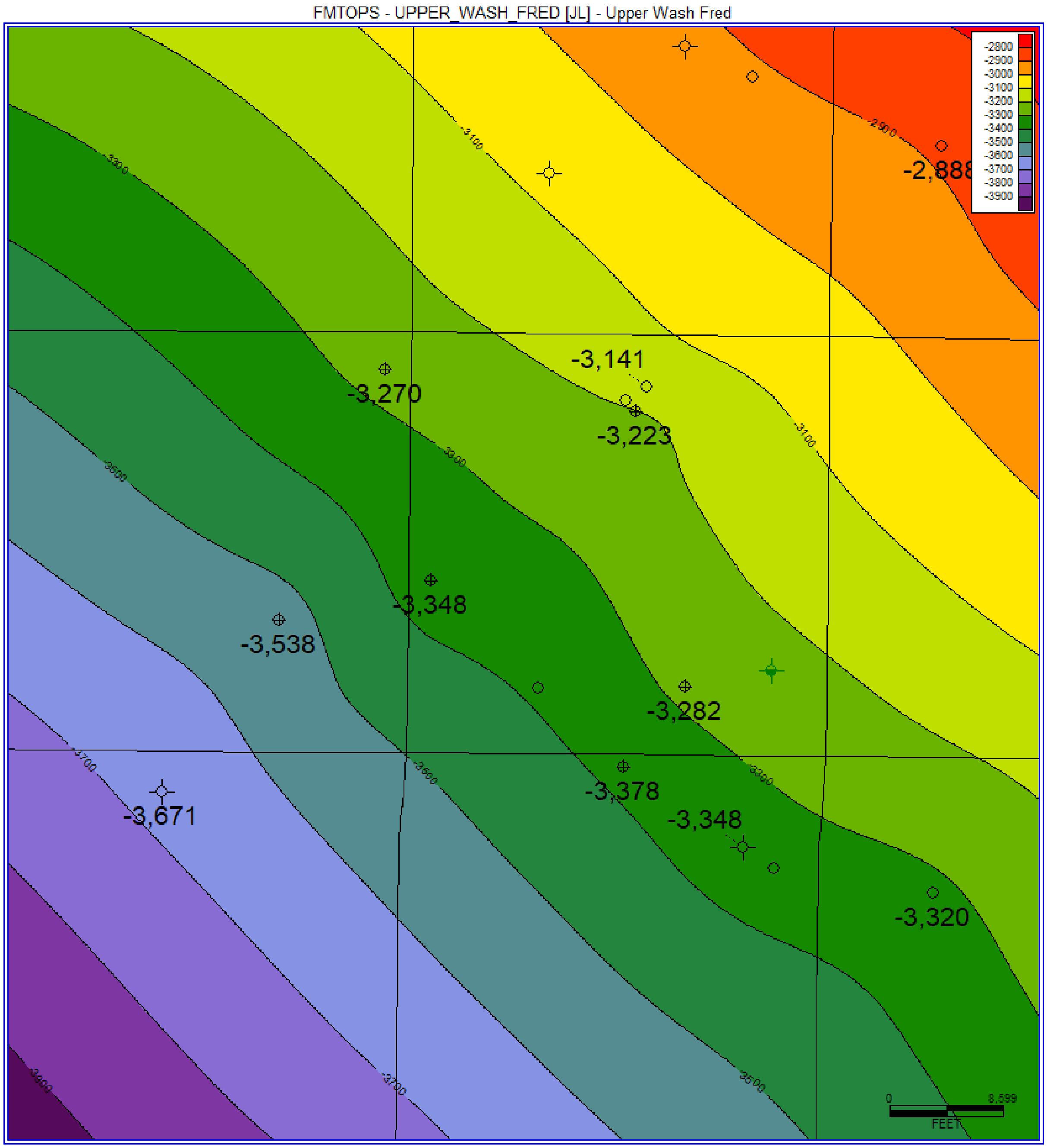

Figure 21. Top of Upper Washita-Fredericksburg Shale Structure Map

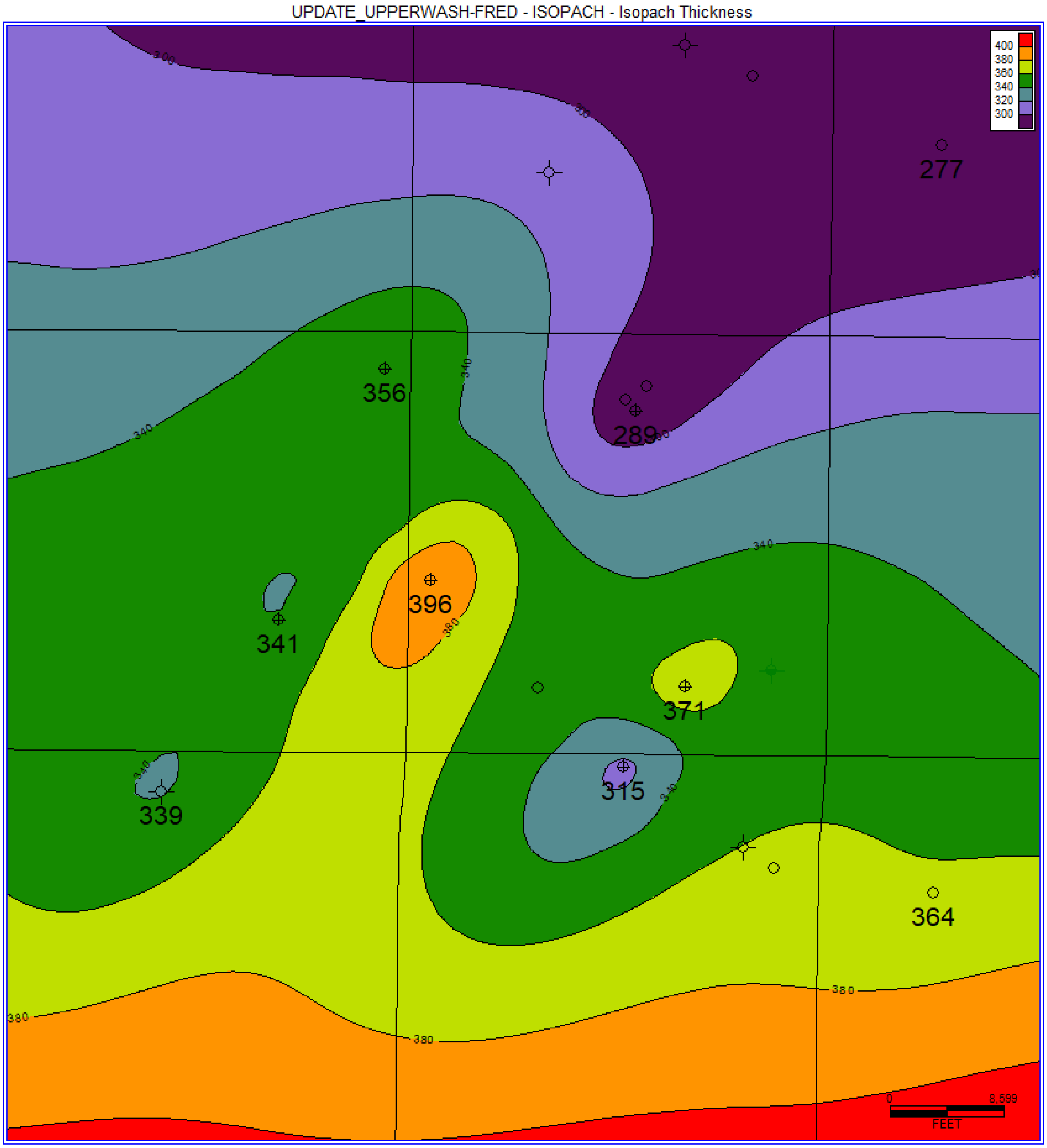

Figure 22. Upper Washita-Fredericksburg Shale Gross Isopach Map

The elevation of the Big Fred sand is -3879 to - 3512 ft SS around the characterization wells (**Figure 23)**, and the thickness ranges from 412 - 484 ft (**Figure 24)**. The Big Fred dips to the southwest at 58.1 ft per mile and its thickness increases to the southwest.

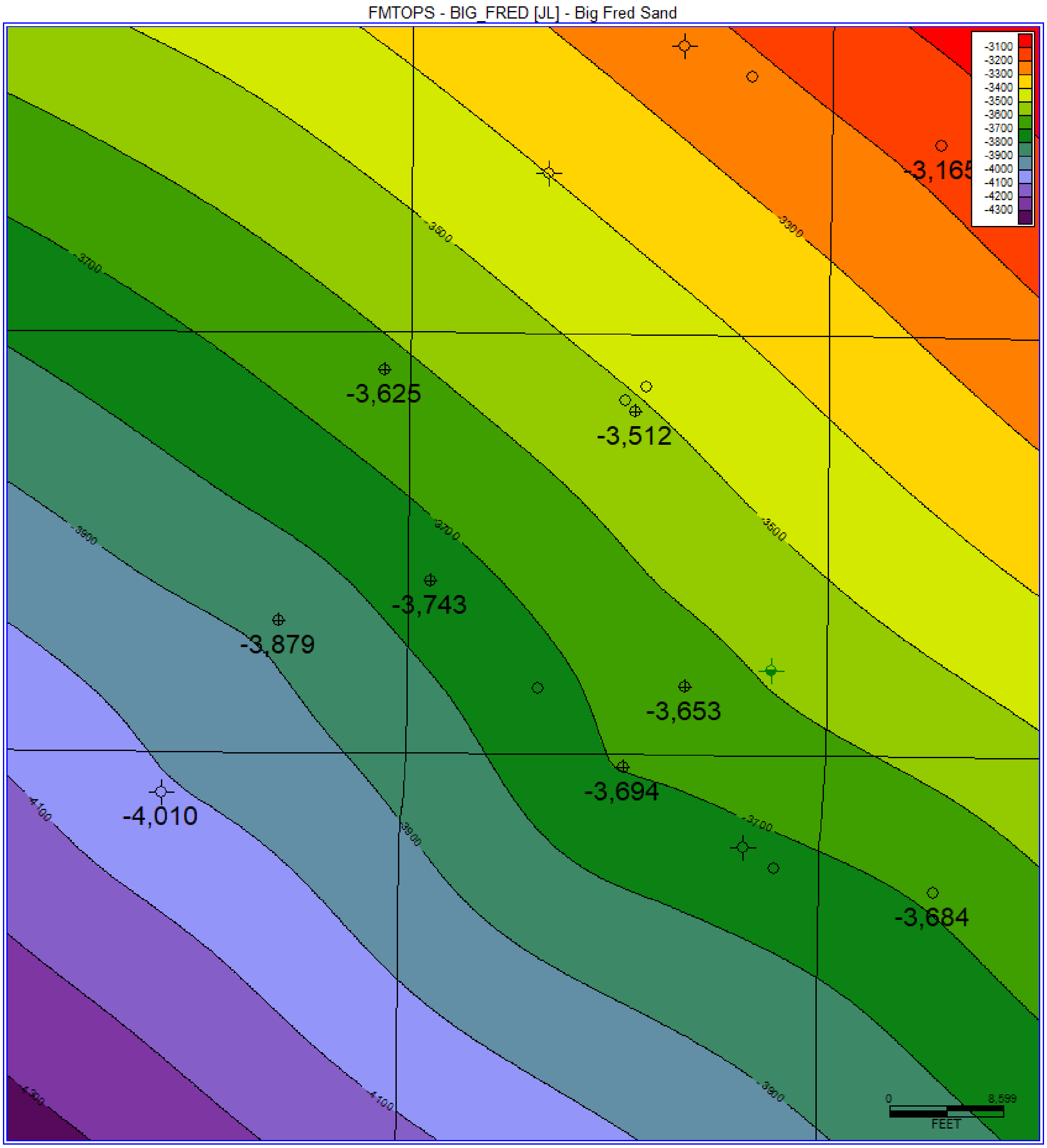

Figure 23. Top of "Big Fred" Sand Structure Map

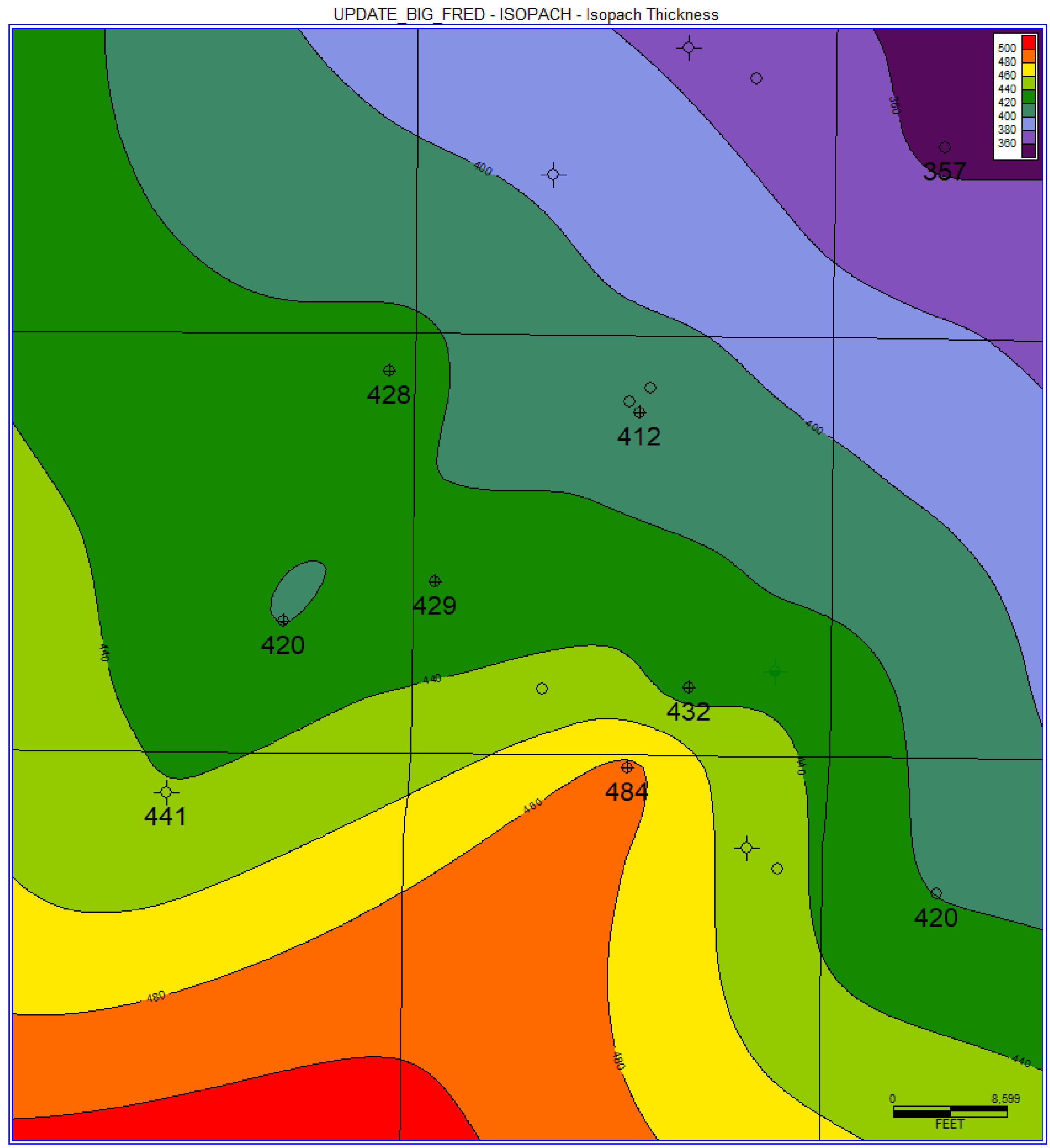

Figure 24. "Big Fred" Sand Gross Isopach Map

The elevation of the Basal Washita-Fredericksburg shale is -4299 to - 3924 ft SS around the characterization wells (**Figure 25)**, and the thickness ranges from 314 - 399 ft (**Figure 26)**. The Big Fred dips to the southwest at 63.8 ft per mile and its thickness increases to the southwest from 314 to 465 ft.

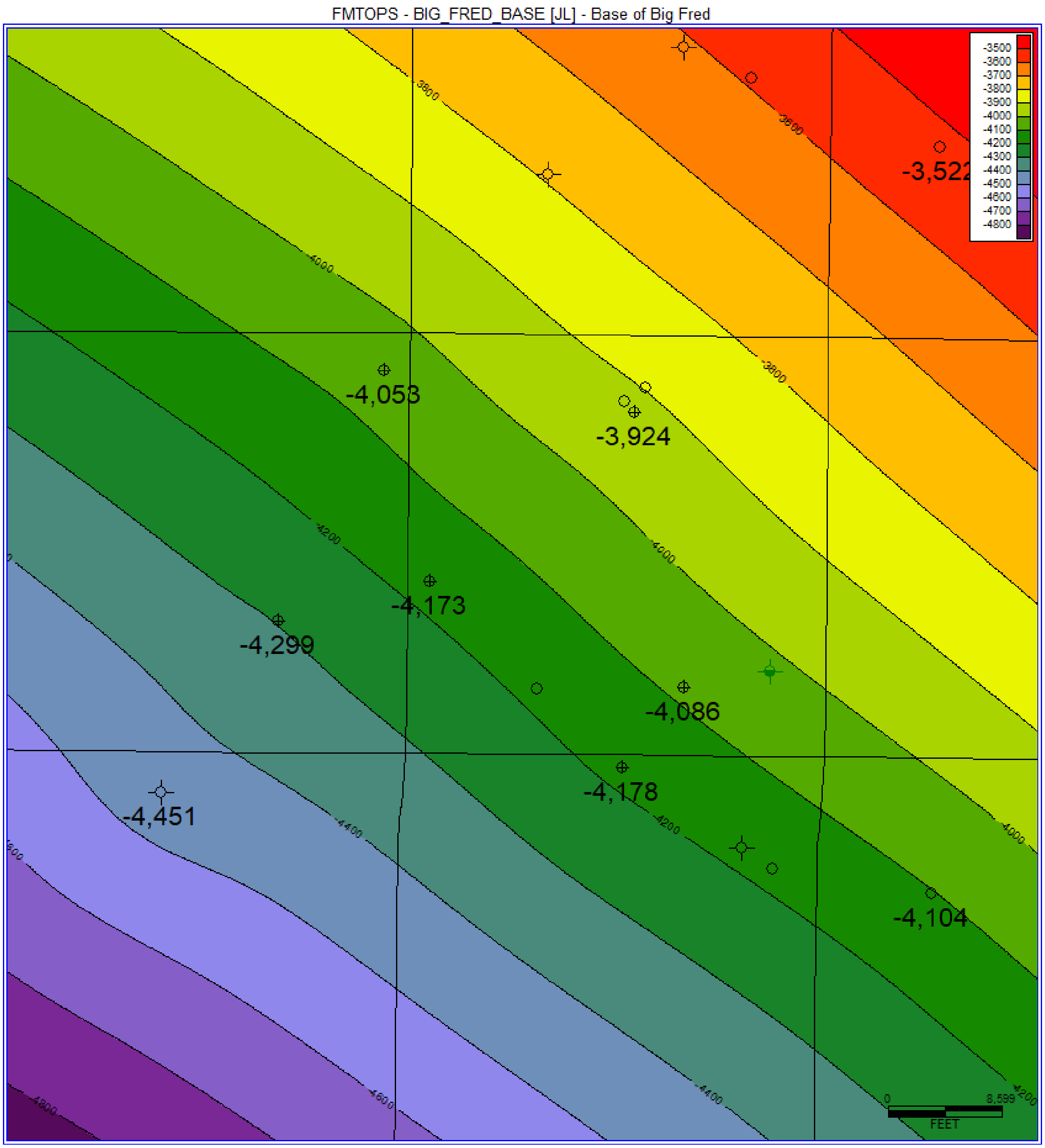

Figure 25. Top of Basal Washita-Fredericksburg Shale Structure Map

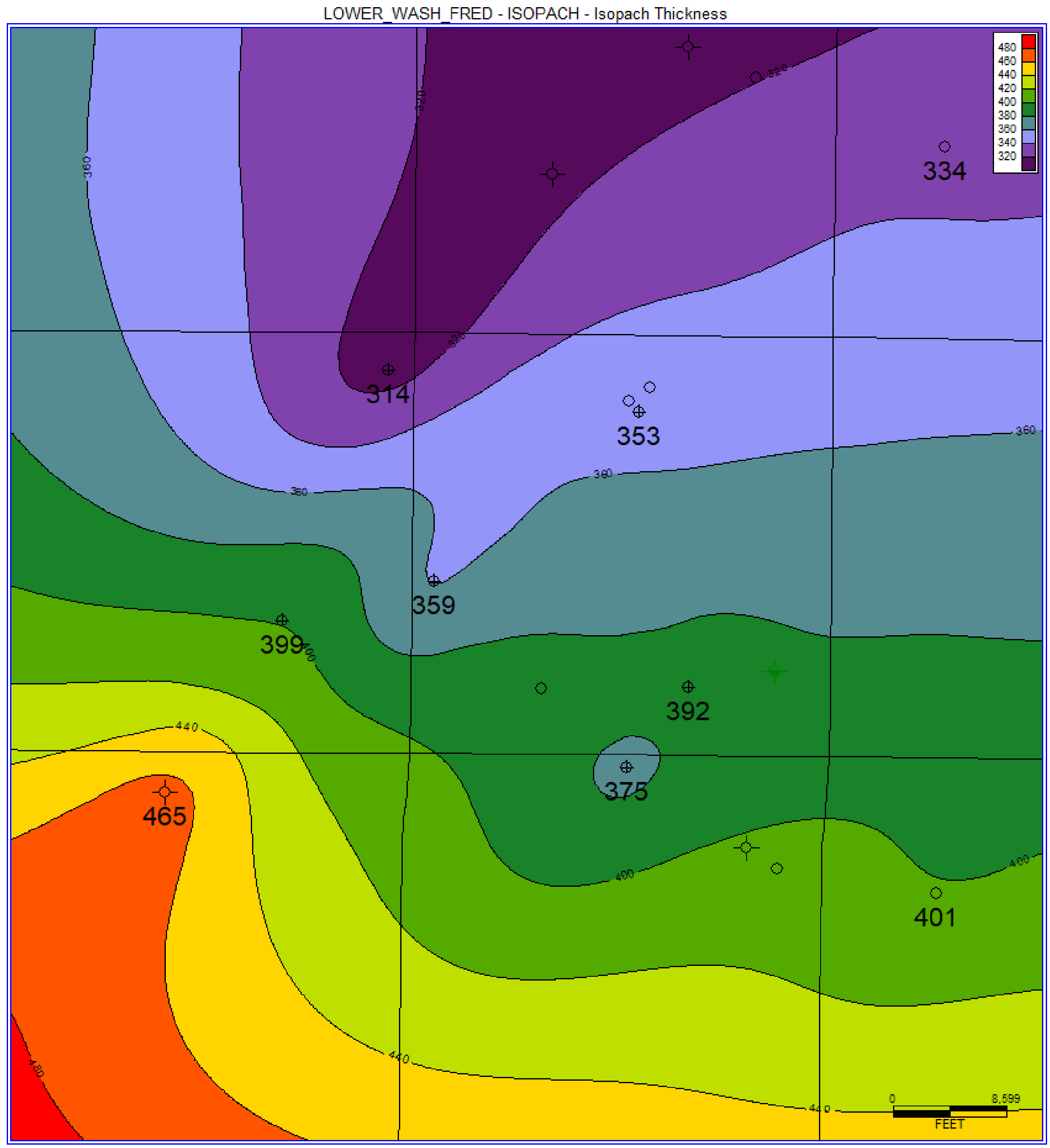

Figure 26. Basal Washita-Fredericksburg Shale Gross Isopach Map

The elevation of the Paluxy Formation is -4698 to - 4277 ft SS around the characterization wells (**Figure 27)**, and the thickness ranges from 534 - 630 ft (**Figure 28)**. The Paluxy dips to the southwest at 72.9 ft per mile and its thickness increases uniformly to the west from 484 to 676 ft. The net sand for the Paluxy Formation ranges from 350 to 496 ft for the characterization wells (**Figure 29**).

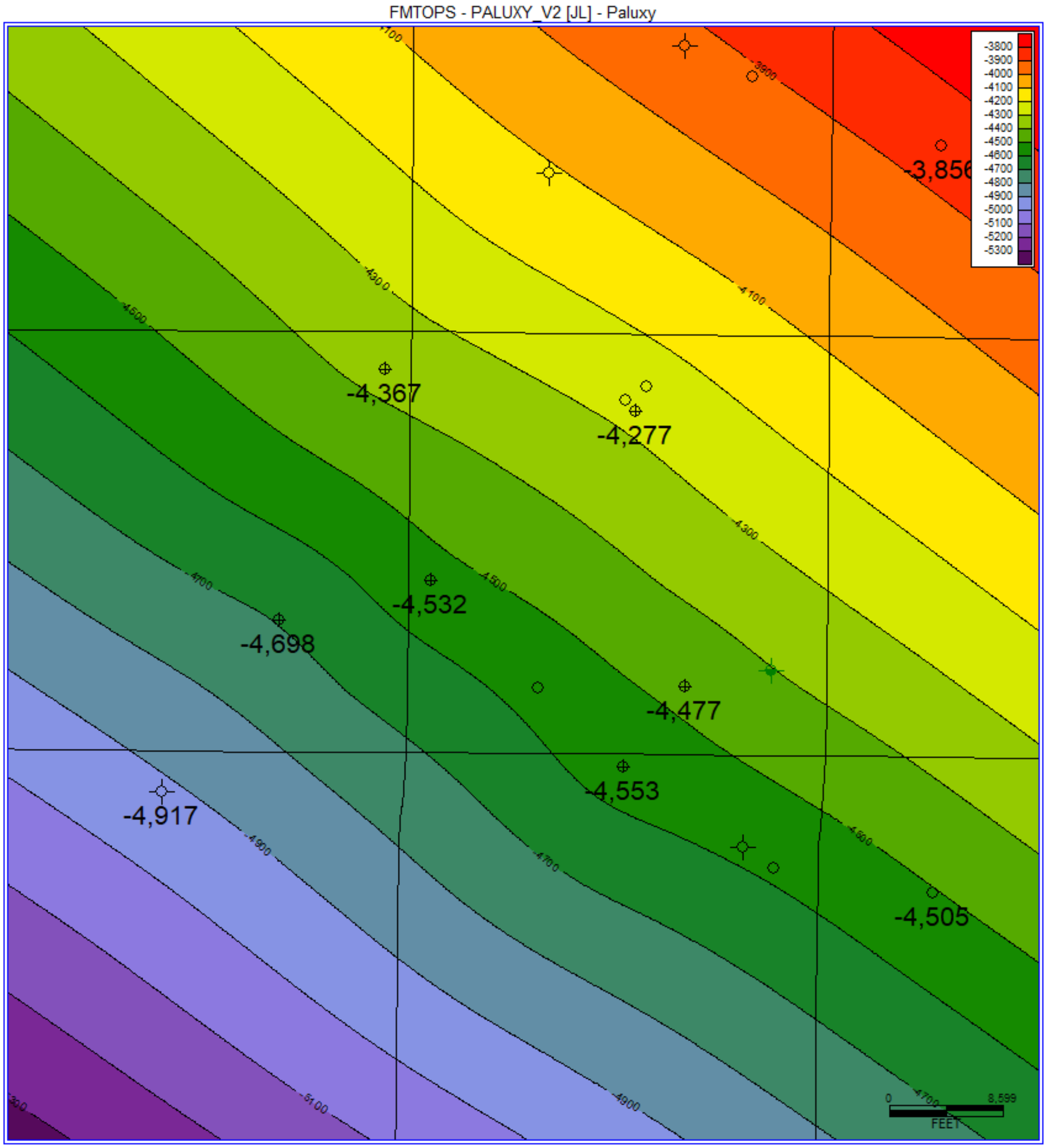

Figure 27. Top of Paluxy Formation Structure Map

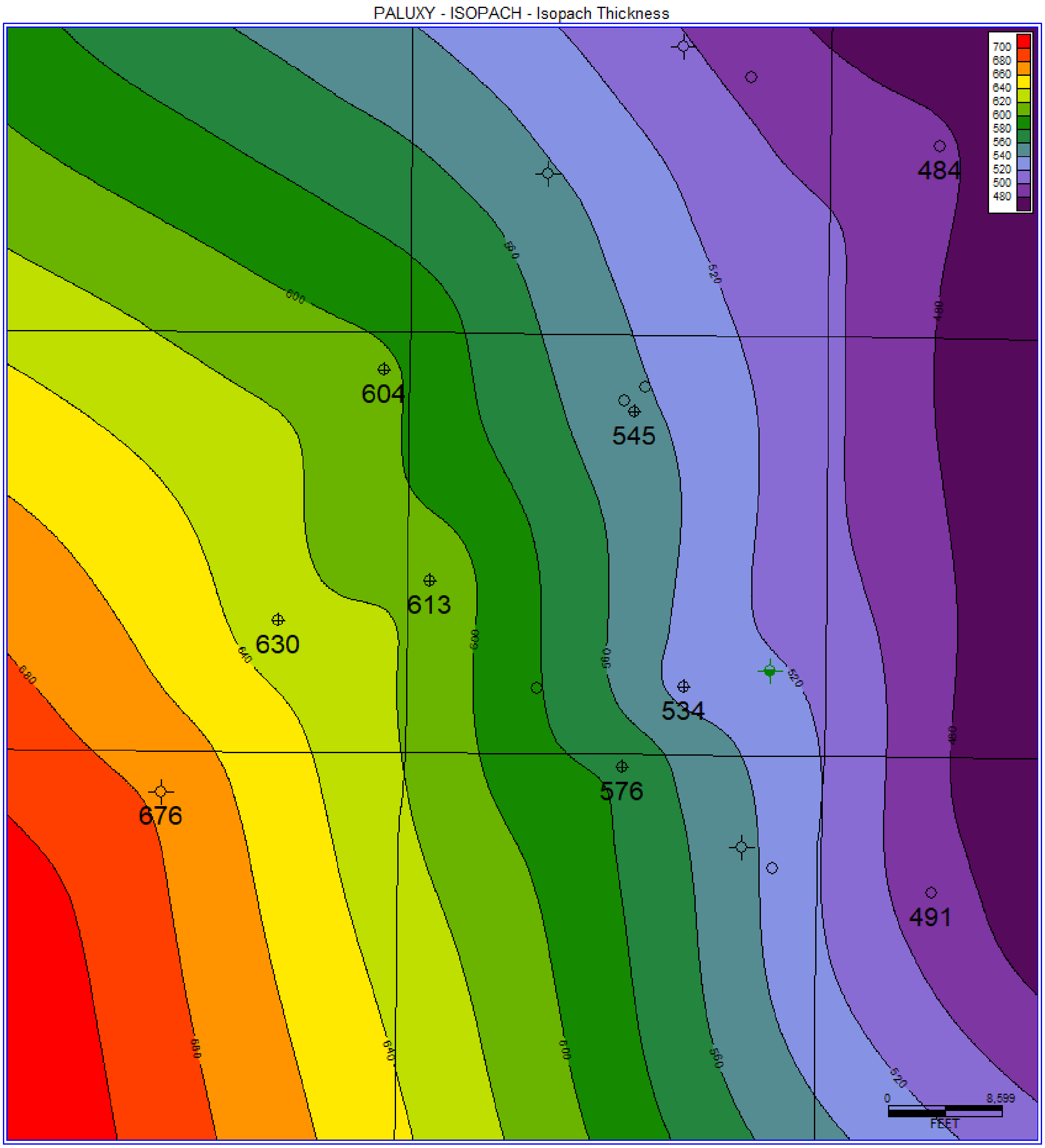

Figure 28. Paluxy Formation Gross Isopach Map

PALUXY - NET_SAND - GR < 80 API

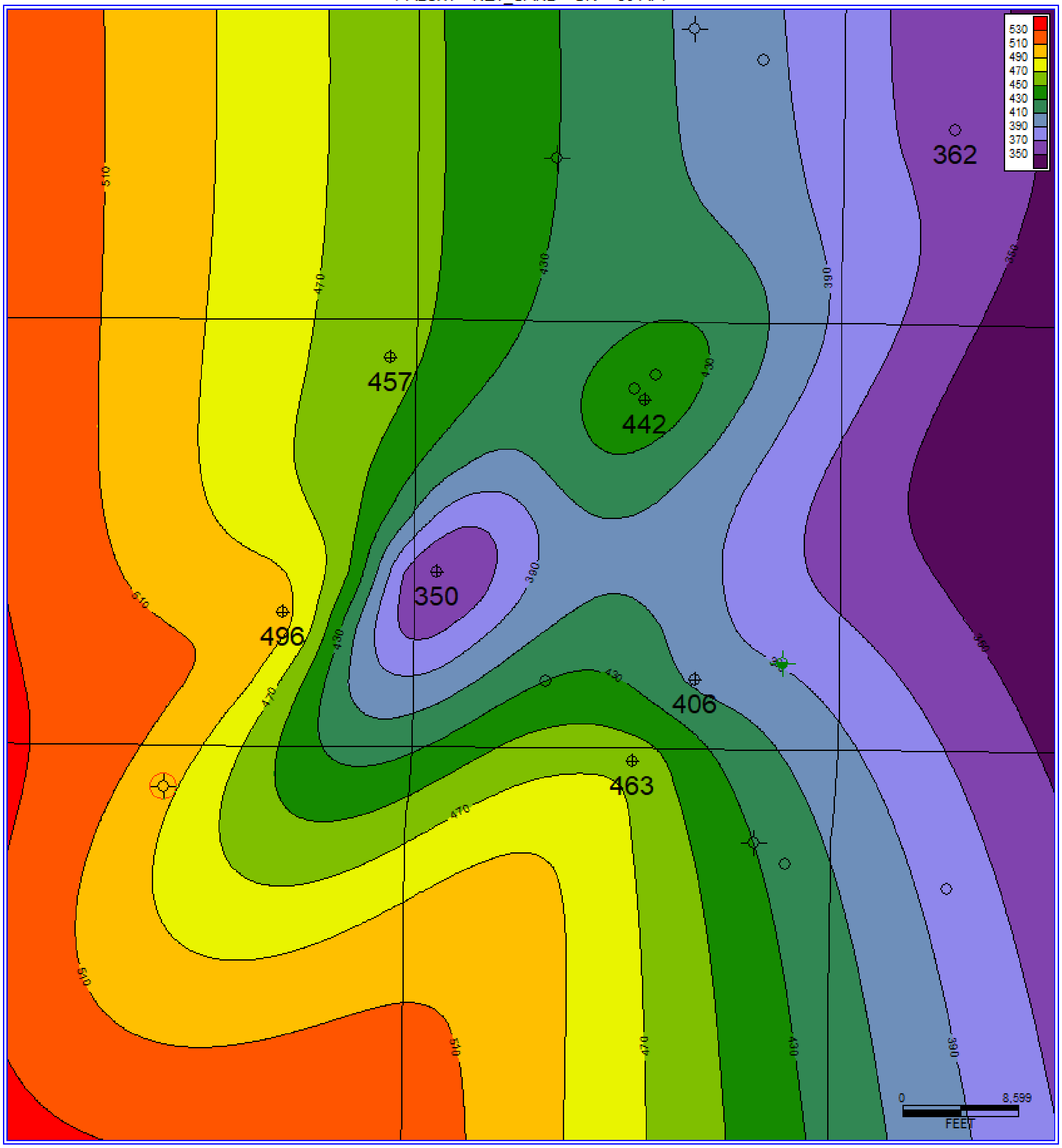

Figure 29. Net sand map of the Paluxy formation

B.3. Faults and Fractures [40 CFR 146.82(a)(3)(ii)]

There are no suspected faults and/or fractures that penetrate the injection zone or confining zone in the AoR or Kemper County. Inactive Paleozoic faults are present below the Cretaceous section of Kemper County at the juncture of the buried Ouachita and Appalachian tectonic belts. These thrust faults are absent above the Paleozoic Unconformity, which can be seen in 2-D seismic lines (**Figure 6 and 7**). As evidenced by the 2-D seismic section, the AOR represents a region of low seismic hazard due to the lack of faults and fractures present through the targeted storage interval and surrounding units (see **Section B.6.**). The closest faults that penetrate Cretaceous strata are 40 miles to the south and west of the Kemper County Storage Complex (**Figure 5**). Faulting within these sediments is likely related to either subsidence as the Mississippi embayment and Gulf of Mexico basin continued to deepen or movement associated with salt structures within the basin [21] [22]. The lack of surface faulting north of the Cretaceous Fault Zone, and consequently at the proposed storage site, is partly due to lesser subsidence in the area and the absence of Jurassic-age salt deposition [23].

B.4. Injection and Confining Zone Details [40 CFR 146.82(a)(3)(iii)]

The injection zone for the Kemper County Storage Complex consists of a series of saline formations in the Cretaceous section of Kemper County, the Paluxy Formation, the "Big Fred" sand, and the Massive sand member of the Lower Tuscaloosa. The target injection interval is in the sands of the Paluxy Formation at the base of the lower Cretaceous. The Tuscaloosa Marine shale serves as the primary confining zone for the Kemper County Storage Complex, while the Upper and Basal Washita-Fredericksburg shale members act as secondary confinement intervals. See **Section B.2.** for depth, thickness, and areal extent of the injection and confining zones in the AoR.

Subsurface geology for the Kemper County Storage Complex was first investigated using data from five characterization wells located in the southwest corner of Kemper County: Mississippi Power Company (MPC) 10-4, MPC 26-5, MPC 34-1, MPC 01-1, MPC 19-1, and MPC 03-1 (**Figure 3**). Each well penetrates the target storage reservoirs and confining zones, and are

[21] Law Engineering Testing Co. (1981). Geologic Evaluation of Gulf Coast Salt Domes: Overall Assessment of the Gulf Interior Region. Office of Nuclear Waste Isolation, Technical Report ONWI-106. 162 p.

[22] Hosman, R. L. (1991). *Regional stratigraphy and subsurface geology of Cenozoic deposits, Gulf Coastal Plain, south-central United States* (No. 91-66). US Geological Survey.

[23] Rosenbalm, A. (2020). Investigating the timing of initial Louann Salt Flow and its relationship with the Gilbertown Fault Zone, Southwest Alabama.

used for subsurface geological characterization, mapping, and numerical modeling [24]. During the drilling process, core was acquired from confining and storage intervals to define the petrophysical properties which are summarized in **Table 2**. The reservoir properties for the storage and confining units were determined from core samples obtained through the characterization wells and were shown to be consistent in nature. This suggests a lateral consistency of necessary reservoir properties across the AOR.

Reservoir characteristics of the injection and confining zones were investigated using core samples, petrographic thin sections, and geophysical logs from the MPC 10-4, MPC 26-5, and MPC 34-1 wells [25]. Routine core analysis (RCA) was used to determine porosity, Klinkenberg permeability, and fluid saturation. Density porosity logs were used to quantify sandstone porosity. Pressure decay permeability analysis was performed on mudrock samples from core and cuttings, and standard petrographic thin section were developed from core samples to determine porosity and mineralogy. This reservoir data was then used to calculate reservoir capacity of the three saline storage reservoirs in the injection zone (Massive sand, “Big Fred” sand, and Paluxy sands). Capacity values were calculated using storage efficiency factors of 7.4%, 14%, and 24%. These efficiency factors represent the statistical confidence level for estimates of p10, p50, and p90, which are the probabilities used to estimate storage capacity. Additionally, Lohr and Hackey (2018) [26] conducted Mercury Injection Capillary Pressure (MICP) analysis on Tuscaloosa Marine shale core samples to determine CO_2 column height retention, porosity, and Swanson permeability. Oklahoma State University analyzed thin sections to determine composition and fabric of the Tuscaloosa Marine shale, and porosity of the reservoir and confining units was determined using the Dean Stark Extraction method [27]. Net storage reservoir thicknesses and porosity were also investigated using triple combo well logs [28]. Porosity, permeability, and calculated storage capacity for sandstone and mudstone units is presented in **Tables 3 and 4**, respectively.

[24] Koperna et al. (2020). See Section B.1.d., footnote #15

[25] Pashin et al. (2020). See Section A.1., footnote #1

[26] Lohr, C. D., & Hackley, P. C. (2018). Using mercury injection pressure analyses to estimate sealing capacity of the Tuscaloosa marine shale in Mississippi, USA: Implications for carbon dioxide sequestration. *International Journal of Greenhouse Gas Control*, *78*, 375-387.

[27] Koperna, G. (2020). *Core Analysis Report (Deliverable 6.1. a)* (No. DOE-SSEB-0029465-60). Southern States Energy Board, Peachtree Corners, GA (United States).

[28] Koperna, G. (2020). *Geophysical Well Log Report (Deliverable 6.2. a)* (No. DOE-SSEB-0029465-61). Southern States Energy Board, Peachtree Corners, GA (United States).

Table 2. Well Core Depths from the Characterization Wells

MPC 26-5			
Depth Range (ft)	**Cored (ft)**	**Recovered (ft)**	**Intervals Cored**
3,587 - 3,643	56	4	Lower Tuscaloosa Massive sand
3,645 - 3,622	17	10.5	Lower Tuscaloosa Massive sand
4,331 - 4,349	18	4.3	Washita-Fredericksburg "Big Fred" sand
MPC 34-1			
Depth Range (ft)	**Cored (ft)**	**Recovered (ft)**	**Intervals Cored**
4,850 - 4,867	17	12.5	Washita-Fredericksburg interval
5,307 - 5,340	33	30	Paluxy Formation
MPC 10-4			
Depth Range (ft)	**Cored (ft)**	**Recovered (ft)**	**Intervals Cored**
3,170 - 3,200	30	26	Tuscaloosa Marine shale
3,200 - 3,210	10	7	Tuscaloosa Marine shale
5,038 - 5,068	30	27.5	Paluxy Formation
5,068 - 5,098	30	30	Paluxy Formation
5,098 - 5,135	37	28	Paluxy Formation
MPC 01-1			
Depth Range (ft)	**Cored (ft)**	**Recovered (ft)**	**Intervals Cored**
3,850 – 3,881	31	31	Upper Washita-Fredericksburg shale
MPC 19-1			
Depth Range (ft)	**Cored (ft)**	**Recovered (ft)**	**Intervals Cored**
3,076 – 3,099	23	0	Tuscaloosa Marine shale
3,099 – 3,125	26	6	Tuscaloosa Marine shale
4,800 – 4,808	8	5	Basal Washita-Fredericksburg shale
4,808 – 4,832	24	20	Basal Washita-Fredericksburg shale
5,320 – 5,344	24	15	Paluxy Formation
5,344 – 5,369	25	25	Paluxy Formation

Table 3. Tabulation of mudstone porosity and permeability data

Mudstone Characteristics			Tuscaloosa Marine Shale	Paluxy Formation
Porosity				
RCA Porosity (%) [29]	**MPC 10-4**		2 – 4	4.2 – 14.7
	MPC 19-1			7.9 and 13.6
MICP Porosity [30]			3.86 – 9.86	
Permeability				
RCA permeability (mD) [29]	**MPC 10-4**		0.54 - 38.1	0.2 - 0.37
	MPC 19-1		3.11 - 13	0.0058 and 0.032
MICP Permeability (mD) [30]			< 0.003	
Pressure decay permeability (nD) [29]	**MPC 26-5**	**Hyperbolic**	194.7	34.4
		Exponential	64.4	23.8
	MPC 10-4	**Hyperbolic**	79.9	
		Exponential	12.4	

[29] Pashin et al. (2020). See Section A.1., footnote #1.

[30] Lohr and Hackey (2018). See Section B.4., footnote #26.

Table 4. Tabulation of sandstone porosity, permeability, and capacity data.

Sandstone Characteristics		Massive sand	Washita-Fredericksburg sand	Paluxy sands
Porosity				
RCA Porosity (%) [38]		28.8	27.4	26.3
RCA Porosity (%) [31]	MPC 10-4			30
	MPC 34-1		> 30.0	
	MPC 19-1			28
Mercury Injection Porosity (%) [31]	MPC 10-4			28.3 – 32.6
Triple Combo Porosity (%) [39]	MPC 26-5	30.0	28.0	28.0
	MPC 34-1	30.0	28.0	27.0
	MPC 10-4	31.0	27.0	28.0
Permeability				
RCA Permeability (mD) [31]	MPC 10-4			1800
	MPC 34-1		600	
Pressure decay permeability MPC 26-5 (nD) [38]	Hyperbolic			34.40
	Exponential			23.80
Capacity				
Storage capacity (Mt/mi^2) [38]	p10	1.82	7.53	4.28
	p50	3.45	14.25	8.10
	p90	5.92	24.43	13.90

[31] Koperna et al. (2020). See Section B.4., footnote #27.

B.4.a Tuscaloosa Marine shale

The Tuscaloosa Marine shale is a succession of interbedded shale, siltstone, and very fine- to fine-grained sandstone that serves as a regional confining unit in the eastern Gulf of Mexico basin. The Marine shale consists of medium to dark gray mudstone that forms laminae to medium beds. The siltstone and sandstone units are light to medium grey, forming laminae to very thick beds (**Figure 30)** [32]. The basal portion of the Marine shale contains graded bedding of shale, siltstone, and sandstone, and these beds have sharp bases and gradational to sharp tops. Other structures included soft-sediment deformation, current ripple cross laminae, and pinstripe, lenticular, and wavy bedding. The Lower and Upper Tuscaloosa together form a progradational succession of fluvial-deltaic deposits that grade upwards from the offshore facies associated with the Marine shale, to the coastal and terrestrial facies of the Upper Tuscaloosa. The Marine shale is the top-seal for the hydrocarbons sourced in the lower Tuscaloosa Group, which is a major source of petroleum in Mississippi and Alabama [33] [34] [35], making it an adequate confining unit for CO_2 storage [36].

Table 3 details porosity and permeability data for the Marine shale, including RCA and Pressure decay permeability [29], and Mercury Injection Capilary Pressure (MICP) data [30]. Porosity measurements from fresh cuttings and core samples indicates that porosity of the mudrocks is on the order of 2 - 4%, although these values appear to reflect alteration of the mudrock during retrieval and preparation of the samples. Permeability values from RCA in the Marine shale show a wide range of permeability from 0.54 to 38.1 mD. Curves fitted to the pressure decay analysis for wells MPC 25-5 and MPC 10-4 data yielded permeability values of 194.7 and 79.9 nD for the Hyperbolic segment, and 64.4 and 12.4 nD for the Exponential segment, respectively. MICP analysis conducted on core and cuttings from the Marine shale yielded porosity values of 3.86 – 9.86%, and Swanson permeability values less than 0.003 mD. Moreover, it was demonstrated that the Tuscaloosa Marine shale can retain a CO_2 column height of 100 meters before any CO_2 intrusion, suggesting desirable sealing ability [30].

[32] Koperna et al. (2020). See Section B.1.d., footnote #15.

[33] Galicki (1986). See Section B.1.d., footnote #18.

[34] Mancini et al. (1987). See Section B.1.c., footnote #12.

[35] Bebout et al. (1992). See Section B.1.d., footnote #20

[36] Koperna et al. (2020). See Section B.1.d., footnote #15.

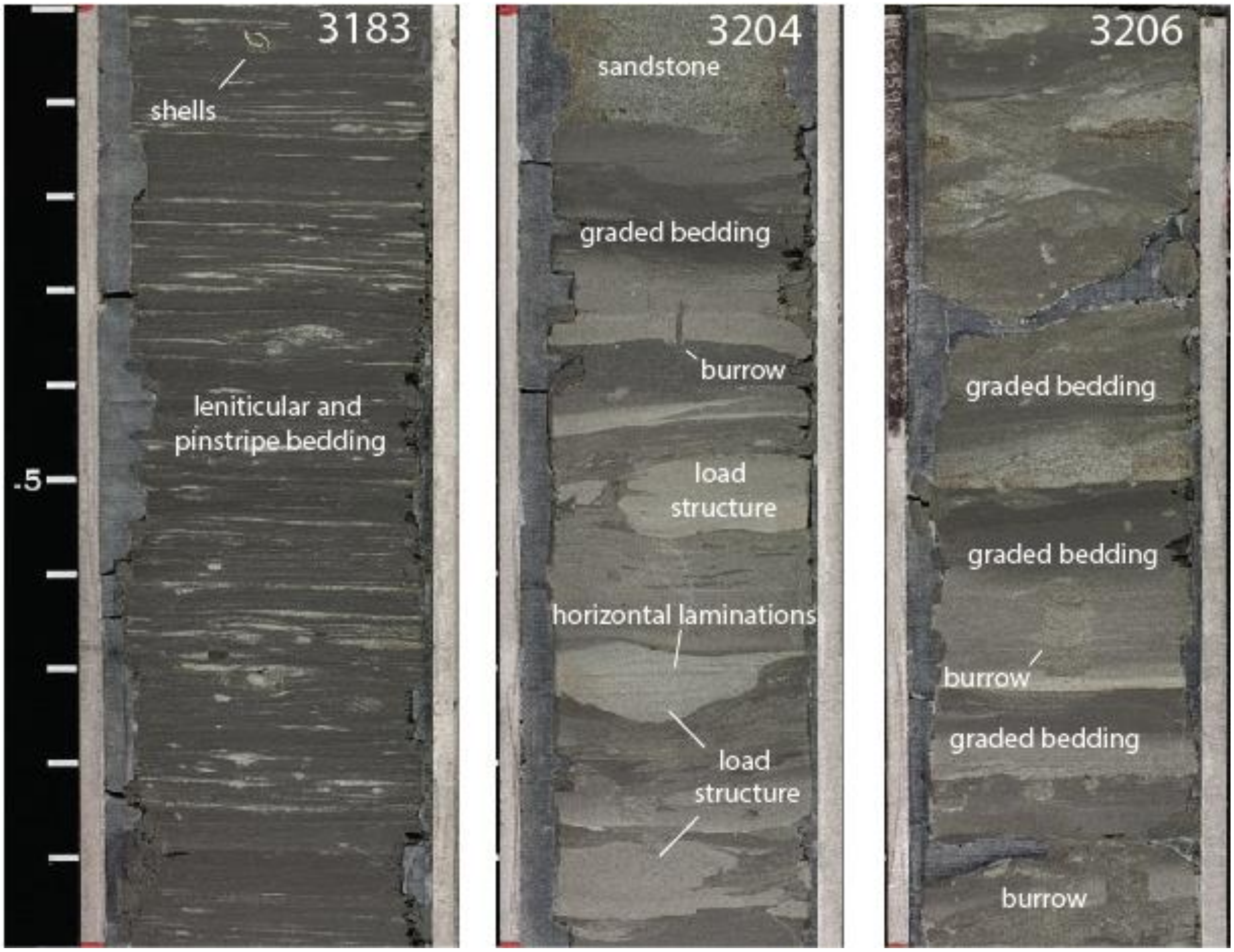

Figure 30. Tuscaloosa Marine Shale Core from MPC 10-4.

B.4.b Lower Tuscaloosa

The Lower Tuscaloosa Massive sand marks the top of the injection zone, directly underlying the Tuscaloosa Marine shale confining zone and is interpreted to have formed in a fluvial to coastal environment [37]. This unit consists of an interval of thickly bedded, very poorly sorted, medium-grained consolidated sandstone while a basal conglomerate forms the lower portion of the Massive sand [38]. RCA of the Massive shows a porosity value of 28.8% [38], while porosity derived from triple combo logs run on the characterization wells yielded porosity values of 30 and 31% [39]. CO_2 storage capacity for the Massive sand was calculated at 1.82, 3.45, and 5.92 Mt / mi^2 for estimates of p10, p50, and p90, respectively.

[37] Mancini et al. (1987). See Section B.1.c., footnote #12.

[38] Pashin et al. (2020). See Section A.1., footnote #1.

[39] Koperna et al. (2020). See Section B.4., footnote #28.

B.4.c Upper Washita-Fredericksburg shale

In the upper part of the Washita-Fredericksburg interval, and overlying the "Big Fred" sand, is a mudstone assemblage that is proposed as one of the secondary confinement intervals for the Paluxy Formation. The interbedded sandstone and mudstone units resemble those of the Paluxy Formation and lower Washita-Fredericksburg interval. Mudstone X-ray diffraction mineralogy of mudstone from well MPC 26-5 in the Washita-Fredericksburg shows 35.3% clay, 63.2% quartz, 1.5% carbonate, with most of the clay being smectite [40]. Correlation of mudstone units in the Washita-Fredericksburg interval shows that individual mudstone layers have sufficient continuity to contain the migration of injected CO_2 in and around the Kemper energy facility [41]. Several Washita-Fredericksburg sandstone units are known to produce hydrocarbons in Mississippi, demonstrating that relatively thin shale beds within the Washita-Fredericksburg interval succession can form effective reservoir seals [42] [43] [44]. This red mudstone succession likely represents the abandonment of the fluvial channel facies in the "Big Fred" sand.

B.4.d. "Big Fred" Sand

The "Big Fred" sand makes up the central portion of the Washita-Fredericksburg interval and consists of a succession of quartzose sandstone, pebble and cobble conglomerate and red and gray mottled mudstone [45]. RCA of the Washita – Fredericksburg sands shows porosity values of 27.4% [40] and 30% [46], while porosity derived from triple combo logs yielded porosity values of 27 and 28% [47]. CO_2 Storage capacity for the Washita – Fredericksburg sands was calculated at 7.53, 14.25, and 24.43 Mt / mi^2 for estimates of p10, p50, and p90, respectively. Grain size decreases upwards in section from conglomeritic sand to fine sand, silt, and mud [48] [45]. The

[40] Pashin et al. (2020). See Section A.1., footnote #1.

[41] Koperna et al. (2020). See Section B.1.d., footnote #15.

[42] Frascogna, X. M., editor (1957). Mesozoic-Paleozoic producing areas of Mississippi and Alabama: Mississippi Geological Society, v. I, 139 p.

[43] Frascogna, X. M., editor (1957). Mesozoic-Paleozoic producing areas of Mississippi and Alabama: Mississippi Geological Society, v. I, 139 p.

[44] Galicki (1986). See Section B.1.d., footnote #18.

[45] Pashin et al. (2008) See Section B.1.d., footnote #14.

[46] Koperna et al. (2020). See Section B.4., footnote #27.

[47] Kopera et al. (2020). See Section B.4., footnote #28

[48] Renken et al. (1989). See Section B.1.d., footnote #16.

Washita-Fredericksburg interval is interpreted as fluvial conglomerate and interfluvial redbeds [48] [49].

B.4.e Washita- Fredericksburg Basal Shale

The basal shale of the Washita- Fredericksburg interval contains mudstone with isolated sandy units which act as an overlying seal for CO_2 storage in sands of the Paluxy Formation [50].This gray, silty mudstone has a blocky appearance resulting from inclined fractures, interpreted as blocky peds produced during soil development [51]. The bottom part of the Basal shale contains a network of sandstone-filled cracks, providing evidence for desiccation and sand infiltration through a soil profile. The gray appearance of the infiltrating sand may be a secondary feature resulting from the migration of reducing fluids through the sandstone during its initial burial and diagenesis [50]. This unit is present throughout the east-central Gulf of Mexico Basin, making it a suitable and regionally extensive seal. Renken et al. (1989) [48] and Pashin et al. (2008) [49] suggested that the Washita-Fredericksburg contains fluvial and interfluvial redbeds similar to those in the underlying Paluxy Formation.

B.4.f. Paluxy Formation

The Paluxy Formation is a redbed succession with three major lithofacies: 1) the conglomerate lithofacies, 2) the sandstone lithofacies, and 3) the mudstone lithofacies [50]. The Paluxy sands are composed of thick- to very- thick bedded sandstone packages with regular cross-bedding structures separated by thinner mudstone laminae (**Figure 31 and 32**) [52].The sand is dominantly fine- to medium-grained, while some intraclastic and extraclastic granules and pebbles are locally present along cross-bed foresets [52]. The Paluxy Formation has been interpreted to represent sandy braided fluvial (sandstone and conglomerate) and interfluvial deposits (mudstone) [53].

The Paluxy Sand is composed of quartz, feldspar, and lithic fragments, and is classified as subarkose and feldspathic litharenite according to the Folk (1980) [54] classification [55]. Quartz

[49] Pashin et al. (2008) See Section B.1.d., footnote #14.

[50] Koperna et al. (2020). See Section B.1.d., footnote #15.

[51] Retallack, G. J. (1990). Soils of the Past—An Introduction to Paleopedology: Boston, Unwin– Hyman, 520 p.

[52] Pashin et al. (2020). See Section A.1., footnote #1.

[53] Folaranmi (2015). See Section B.1.d., footnote #17.

[54] Folk, R. L. (1980). *Petrology of sedimentary rocks*. Hemphill publishing company.

[55] Pashin et al. (2020). See Section A.1., footnote #1.

grains are angular to subrounded and slightly elongate to spherical. Quartz content ranges from 65 – 95%, while feldspar and lithic fragments are present in relatively equal proportions in the Paluxy sands. Orthoclase and plagioclase feldspar are both present and commonly partially dissolved or vacuolized and result in secondary porosity. Lithic rock fragments in the Paluxy sand include metamorphic rocks, igneous rocks, and a few grains of oolitic chert. Common accessory minerals include biotite and muscovite, with minor amounts of zircon grains, calcite cement, and kaolinite in pore spaces. Like the Washita-Fredericksburg, the anomalously high-water saturation (100%) in the cores from the clay-rich intervals in the Paluxy was likely due to the shallow burial depths and resulting low thermal maturity and immature clay minerals. The RCA results for the Paluxy Sands shows an average of 1.8 D permeability and 28% porosity for the MPC 10-4 samples, and porosity derived from triple combo logs run on the three Phase II characterization wells suggests porosity of 27 and 28% in the Paluxy sands [56]. Additionally, Paluxy sand core samples underwent steady- state CO_2/Brine Relative Permeability Measurements at the University of Wyoming and found a porosity and permeability of 30% and 1601 mD, respectively [56]. Scanning electron microscopy of the Paluxy sands thin sections reveal a predominance of quartz, and a porosity of 20 – 25% was determined from BSE images [57]. Other minerals include feldspar, clay (kaolinite, smectite, and illite), and carbonates (calcite, dolomite, and siderite). Clay minerals are present as a coating on other mineral phases or bridges between grains. Cross-sectional slices extracted from 3D X-ray CT images were analyzed and yielded an average porosity of 26% [57]. In reactive transport simulations, the carbonate minerals showed the greatest alterations. Clay and aluminosilicate minerals were altered to a lesser degree. The mineral dissolution resulted in a porosity increase from 25 – 32% [57]. Calcite will dissolve more quickly in regions where brine saturation is higher, while other minerals grains are left mostly unchanged. These reactive phases are anticipated to dissolve along all depths in the Paluxy. Pore network modeling showed an increase in permeability from 1555.4 mD to 8000 mD. Curves fitted to the pressure decay analysis for mudstones in the Paluxy from well MPC 26-5 data yielded permeability values of 34.4 and 23.8 nD for the Hyperbolic and Exponential segment, respectively [58]. Capacity for the Paluxy sands was calculated at 4.28, 8.10, and 13.9 Mt / mi^2 for estimates of

[56] Koperna et al. (2020). See Section B.4., footnote #27.

[57] Beckingham, L., Qin, F., Anjikar, I., & Bensinger, J. (2020). *Evaluation of water-rock-CO2 interactions in the Paluxy formation at the Kemper County Energy Facility (Deliverable 6.3)* (No. DOE-SSEB-0029465-33). Southern States Energy Board, Peachtree Corners, GA (United States).

[58] Pashin et al. (2020). See Section A.1., footnote #1.

p10, p50, and p90, respectively. See **Section B.8.** for how the mineralogy of the Paluxy Formation impacts any geochemical reactions and on the compatibility with the CO_2 stream.

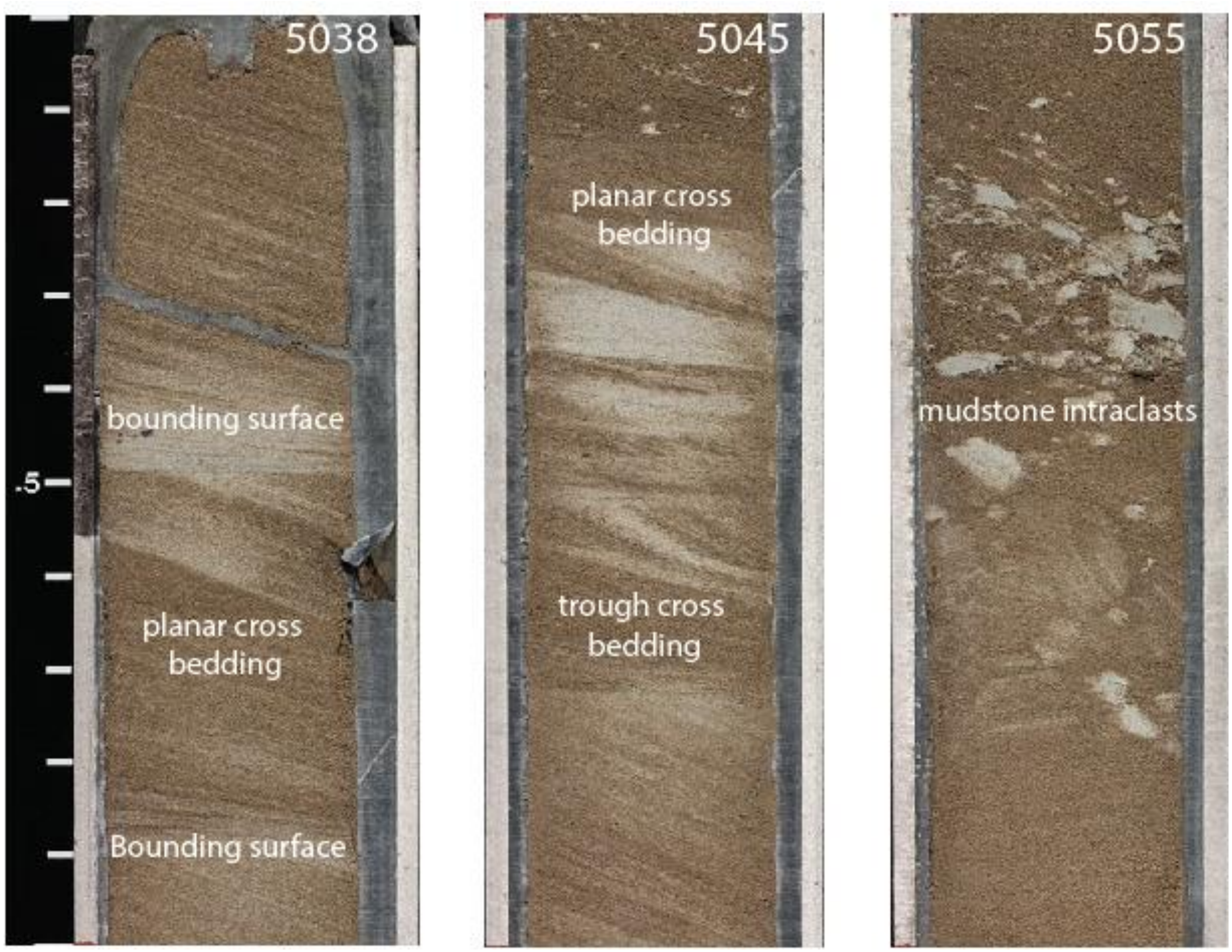

Figure 31. **Paluxy Core from Well MPC 10-4.**

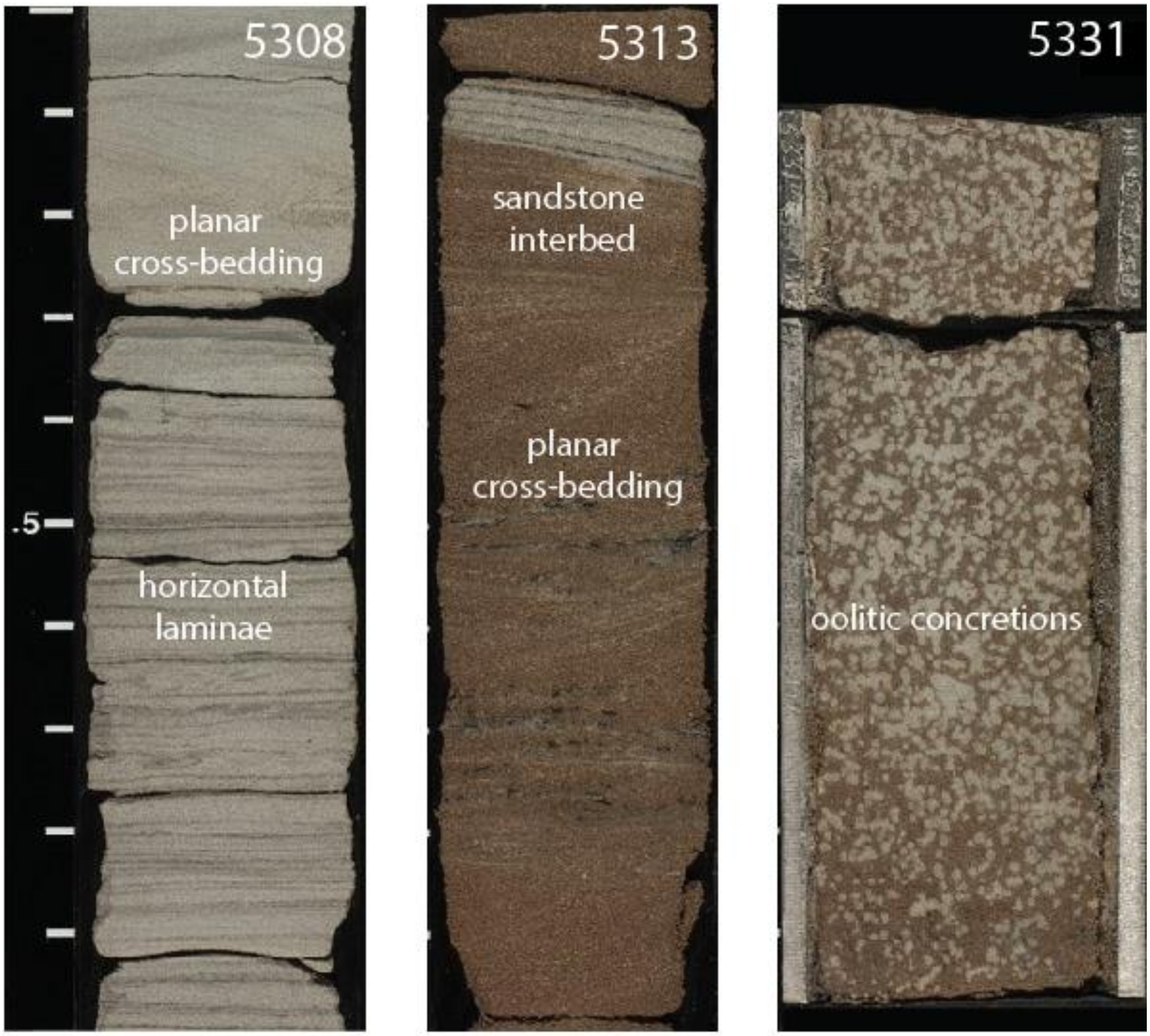

Figure 32. Paluxy Core from Well MPC 34-1.

B.5. Geomechanical and Petrophysical Information [40 CFR 146.82(a)(3)(iv)]

A One-Dimensional Mechanical Earth Model (1-D MEM) was developed to determine a fracture gradient for geologic formations within the injection zone. The calculated fracture gradient for each formation establishes the maximum allowable injection pressure that prevents fracturing of the reservoir and confining units within the storage zone. The mechanical model was first developed using well MPC 01-1 which contained both geophysical well logs and rock mechanics core test results. Geomechanics tests were conducted on cored intervals of confining unit shale lithologies from the Upper Washita-Fredericksburg shale. Geomechanics test samples were collected from depths that range from 3,857.15 ft to 3,875.45 ft. The data were collected on samples that were cut from whole core using tests that include Multi-Stage Triaxial Compressive Strength, Brazilian Tensile Strength, and Uniaxial Pore Volume Compressibility.

The elastic moduli determined from the core test results are indicated in **Table 5**. The reported Poisson's Ratio were variable while Young's Modulus values are low suggesting that these rocks behave in a ductile rather than brittle fashion. In addition, the Biot Coefficient values are high indicating that these rocks are relatively compliant. The estimated Unconfined Compressive Strength (UCS) ranges from 1,748 psi to 4,331 psi from two samples. The tests indicate variability in the UCS results and overall suggest that the rocks are relatively weak in compression. In addition, the tensile strength of the samples ranges from 23 psi to 150 psi indicating that the shale lithologies are very weak in tension. Although the tested lithologies have lower strength, the elastic moduli and compressive strength test results support that these samples are not brittle and behave in a ductile fashion under stress. Ductile shale lithologies typically provide good seal quality because they inhibit the propagation of fractures due to their ability to self-heal.

Table 5. Elastic mechanic properties determined from the Uniaxial Pore Volume Compressibility tests.

Depth	Bulk Modulus	Biot Coefficient	Young's Modulus	Poisson's Ratio
3857.15	1.17	0.80	1.01	0.15
3865.65	2.55	0.90	0.89	0.27
3874.80	2.21	0.70	1.27	0.12

After determining the static elastic moduli from core test results, the dynamic elastic moduli were estimated using the dipole sonic and bulk density logs for well MPC 01-1. The dynamic elastic moduli were correlated with core derived static values using correlations for sandstones and shales determined by [59]. The overburden stress gradient was determined to be 0.96 psi/ft using well logs and a pore pressure gradient was determined to be 0.415 – 0.435 psi/ft from well logs and a Modular Formation Dynamic Test (MDT) at well MPC 03-1. In addition, the regional tectonic stress direction was determined to be a normal faulting regime which was incorporated

[59] Morales, R.H. and Marcinew, R.P., 1993, Fracturing of Higher-Permeability Formations: Mechanical Properties Correleations: SPE Annual Technical Conference and Exhibition, Houston, Texas, October 1993, Paper Number SPE 26562-MS.

into the mechanical model. The data were fed into the Poroelastic Horizontal Strain Model which computed the minimum and maximum principal horizontal stresses. The mechanical model for well MPC 01-1 was validated using wellbore breakouts from the caliper log which demonstrated a good correlation. The 1-D MEM was then applied to the rest of the five wells within the AoR that contained geophysical well logs and satisfactorily predicted breakouts which validated the entire model.

The average minimum principal stress for each formation was determined from the mechanical model and represents the pressure required to fracture the formation at depth. For the entire storage zone including the reservoir and confining units, 90% of the mean formation fracture gradient ranges from 0.61 psi/ft to 0.65 psi/ft. The Paluxy Formation is the primary injection interval and has an estimated 90% fracture gradient of 0.61 psi/ft.

B.6. Seismic History [40 CFR 146.82(a)(3)(v)]

Central Mississippi, and Kemper County in particular, are areas with historically moderately low earthquake risk. Mississippi is part of the Stable Continental Region which comprises most of eastern North America [60]. In this region, most of the earthquakes are low magnitude and occur at irregular intervals. The estimated Peak Ground Acceleration (PGA; expressed as a percentage of the gravity constant, 9.8 m/s^2) for the Kemper County Storage Complex is 6 - 10% g (**Figure 33**), meaning that there is a there is a 2% probability that Kemper County will experience Peak Ground Acceleration of 6% to 10% g due to seismic activity within 50 years. Conversely, there is a 98% probability that PGA of this magnitude would not be achieved

[60] Wheeler , , R.L., 2003, Tectonic summaries for web-served earthquake responses, southeastern North America: U.S. Geological Survey Open-File Report 03–343, 27 p.

within fifty years. Peak Ground Acceleration of 8 to 10% g corresponds to an earthquake intensity of VI to VII on the Modified Mercalli Intensity Scale and magnitude 5 on the Richter Scale [61].

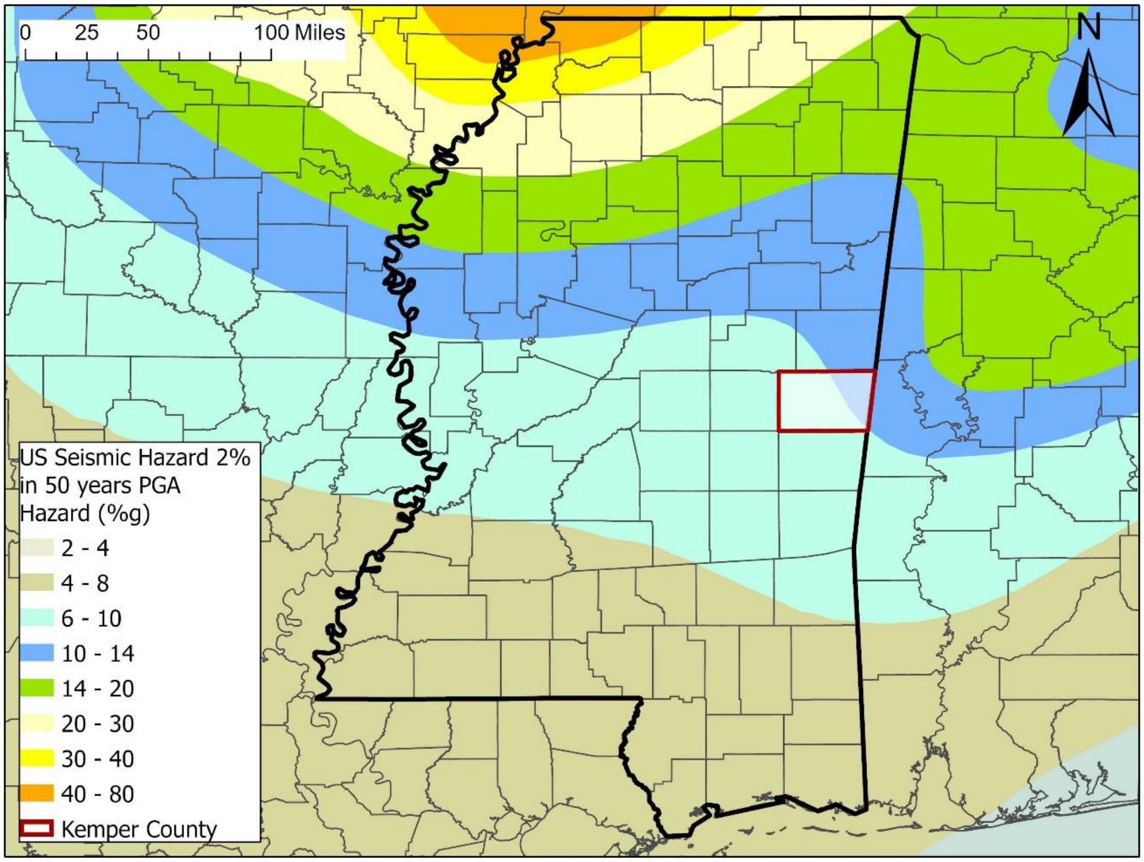

Figure 33. Seismic Hazard Map for Mississippi (Source: USGS, 2014)

The estimated seismic hazard for northern and central Mississippi is elevated due to proximity to the New Madrid seismic zone which encompasses northeastern Arkansas, southwestern Kentucky, southeastern Missouri, and northwestern Tennessee. The southern end of the New Madrid seismic zone is about 40 miles from the northwest corner of Mississippi and approximately 185 miles from the proposed Kemper County Storage Complex. Paleoseismic studies have concluded that during the past 1,200 years, the New Madrid seismic zone has generated earthquakes of magnitude 7 to 8 approximately every 500 years. The New Madrid seismic zone generated a sequence of earthquakes in the winter of 1811 and 1812, which lasted

[61] Bolt, B. (1993). Earthquakes: Revised and Expanded.

for several months and included three earthquakes of estimated magnitude between 7 and 8 [62]. The current seismic hazard map for Mississippi implies that it would take a reactivation of the New Madrid seismic zone of similar magnitude and intensity as the 1811-1812 earthquakes to generate the estimated PGA of 8 to 10 %g in Kemper County.

Figure 34 shows the occurrence of earthquakes throughout Mississippi since 1927. Approximately sixty recorded seismic events in Mississippi since 1927 and only half of which were able to be felt at the surface with the remainder only detectable via instrumentation [63]. The strongest earthquake in Mississippi occurred in 1931 in the Charleston area of Tallahatchie County in northwest Mississippi approximately 120 miles northwest of the proposed Kemper County Storage Complex. The estimated magnitude was 4.7 on the Richter scale and the maximum intensity of VI – VII on the Modified Mercalli Intensity scale (which describes the effects of shaking on the ground and structures) was felt at Charleston [64].

Four earthquakes of low magnitude have been recorded in the vicinity of the proposed Kemper County Storage Complex. In Kemper County, only one earthquake has been recorded near the Mississippi – Alabama state boundary. Three earthquakes were recorded in northern Lauderdale in 2002 and 2012 near the Kemper County line. Details of the four earthquakes are provided in **Table 6**. A larger collection of low magnitude earthquakes were recorded further to the south in Clarke County, MS. These earthquakes may be explained by their proximity to the Gulf Margin Normal Fault Area, which contains normal faults that accommodate extension associated with the massive sediment load deposited on the southern margin of North America [65]. However, there are no observed faults in the Mesozoic-Cenozoic section at the Kemper County Storage Complex [66]. Therefore, no failure of reservoir rock or fault reactivation is expected to occur.

[62] Chung, J., Okok, A., & Rogers, J. D. (2021). Geologic impacts and calculated magnitudes of historic earthquakes in the central United States. *Engineering Geology*, *280*, 105923.

[63] MDEQ, 2021. Fact Sheet 1: Earthquake Epicenters. Mississippi Department of Environmental Quality.

[64] Bograd, M.B.E (2017). *Earthquakes* in *The Mississippi Encyclopedia,* University Press of Mississippi and online, https://mississippiencyclopedia.org/entries/earthquakes/, Accessed March 2, 2021Bolt, B. A., 1993, Earthquakes, W.H. Freeman, N.Y., 331 pp.

[65] Dart, R. L., & Bograd, M. B. (2011). *Earthquakes in Mississippi and vicinity 1811-2010* (No. 2011-1117, pp. 1-1). US Geological Survey.

[66] Koster, J., & Hills, D. (2018). *Seismic Reflection Interpretation in Support of Project ECO2S, Kemper County, MS (Poster)* (No. DOE-SSEB-0029465-17). Southern States Energy Board, Peachtree Corners, GA (United States).

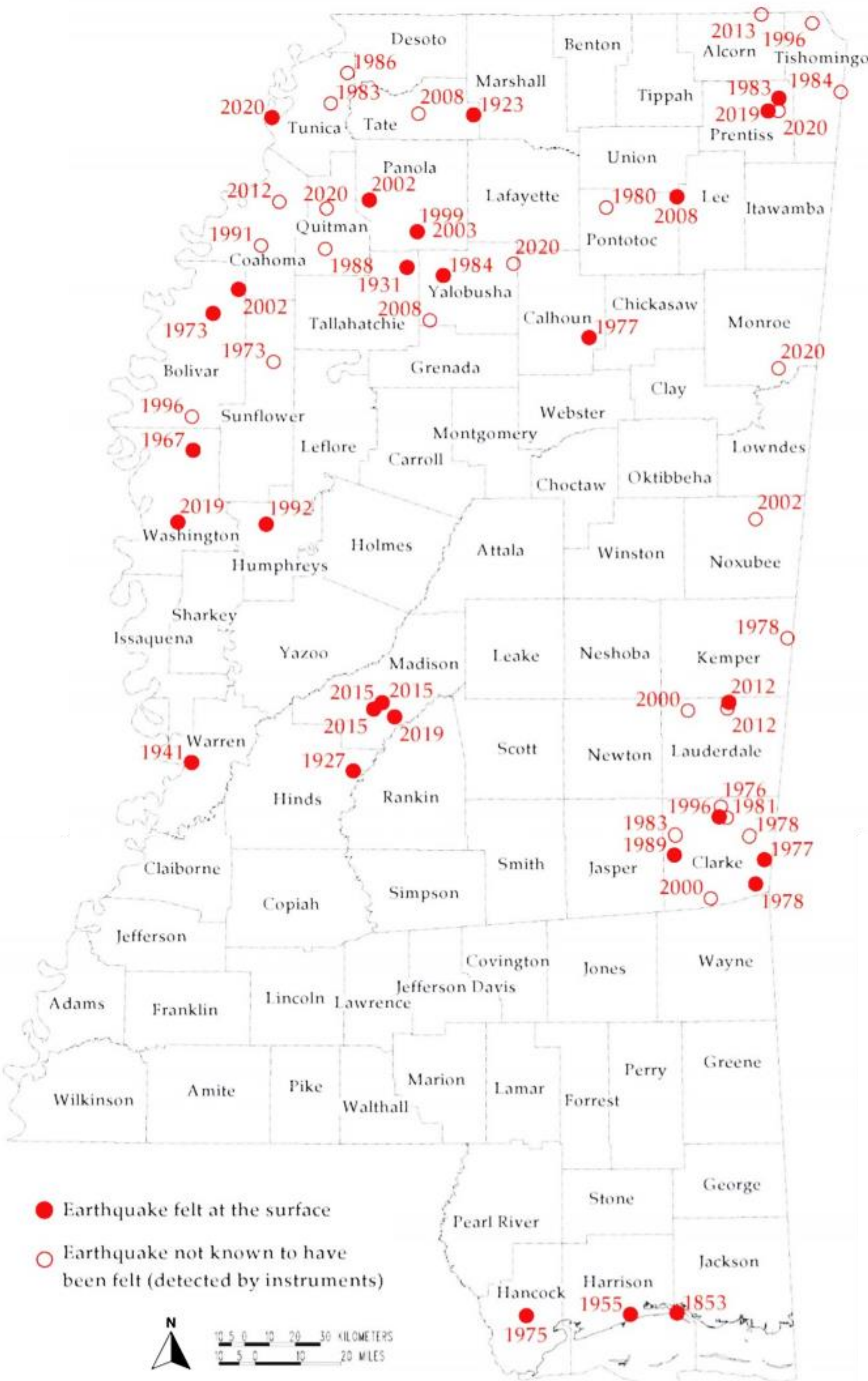

Figure 34. Earthquake Epicenters in Mississippi.

Table 6. Historical Earthquakes Recorded in Kemper County and Vicinity.

Date of Occurrence	Location	Magnitude	Felt at Ground Surface?
January 8, 1978	Kemper County- Alabama Border	3.0	Not Felt
October 10, 2000	Northwest Lauderdale County	2.3	Not Felt
July 27, 2012	Lauderdale County – Meridian Station	2.1	Felt at Surface
July 29, 2012	Lauderdale County – Meridian Station	1.6	Not Felt

B.7. Hydrologic and Hydrogeologic Information [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)]

The major aquifers in the central part of Mississippi are part of the southeastern Coastal Plain aquifer system, which developed within the Mississippi Embayment through the Cretaceous – Tertiary periods. The principal aquifers in central Mississippi strike mainly northwest to southeast and dip to the south-southwest, like the target injection zone of the Kemper County Storage Complex. The aquifers consist mostly of clastic sediment including gravel, sand, clay, chalk, and marl deposited by a cyclic rise and fall of sea levels [67].

The eastern central Mississippi aquifer systems described below (in descending order) are the Wilcox, the Eutaw-McShan, the Tuscaloosa aquifer system, and the Lower Cretaceous aquifer (**Table 7**). The Eutaw-McShan aquifer is considered a single aquifer, while the Tuscaloosa aquifer system is generally sub-divided and consists of the Gordo and Coker aquifers.

[67] Strom, E. W. (1998). Hydrogeology and simulation of ground-water flow in the Cretaceous-Paleozoic aquifer system in northeastern Mississippi (Vol. 98, No. 4171). US Department of the Interior, US Geological Survey.

SYSTEM	SERIES	GROUP	FORMATION	PRINCIPAL AQUIFER	AQUIFER SYSTEM
TERTIARY	EOCENE	WILCOX GROUP	NANAFALIA FORMATION	MIDDLE/LOWER WILCOX AQUIFER SYSTEM	LOWER WILCOX AQUIFER
	PALEOCENE	MIDWAY GROUP	NAHEOLA FORMATION		
			PORTERS CREEK CLAY	AQUITARD	
CRETACEOUS	UPPER	SELMA GROUP	UNDIFFERENTIATED	AQUITARD	
		EUTAW GROUP	EUTAW FORMATION	EUTAW-MCSHAN AQUIFER	
			MCSHAN FORMATION		
		TUSCALOOSA GROUP	GORDO FORMATION	GORDO AQUIFER	TUSCALOOSA AQUIFER SYSTEM
			COKER FORMATION	COKER AQUIFER	
			TUSCALOOSA MARINE SHALE	AQUITARD (PRIMARY CONFINING ZONE)	
			MASSIVE SAND	MASSIVE SAND AQUIFER (SALINE RESERVOIR)	

Table 7. Geologic Units and Principal Aquifers in Central Mississippi. Source: [68].

The Wilcox aquifer is 350 feet thick in Kemper County but is up to 1,000 feet in western Mississippi. The Wilcox crops out in eastern Kemper County and dips towards the axis of the Mississippi embayment. The principal source of recharge is from the outcrop, and groundwater movement is westerly and southwesterly [69]. Groundwater is generally a mixed calcium and sodium bicarbonate salt, with concentrations less than 1,000 mg/L extending up to 70 miles from the outcrop area [69]. Each of the shallow groundwater wells around the Kemper County Storage Complex produce from the Middle or Lower Wilcox (**Figure 35**) for domestic water use and small-scale agriculture.

68 Pashin et al. (2008) See Section B.1.d., footnote #14.

69 Taylor, R. E., & Arthur, J. K. (1992). Hydrogeology of the middle Wilcox aquifer system in Mississippi.

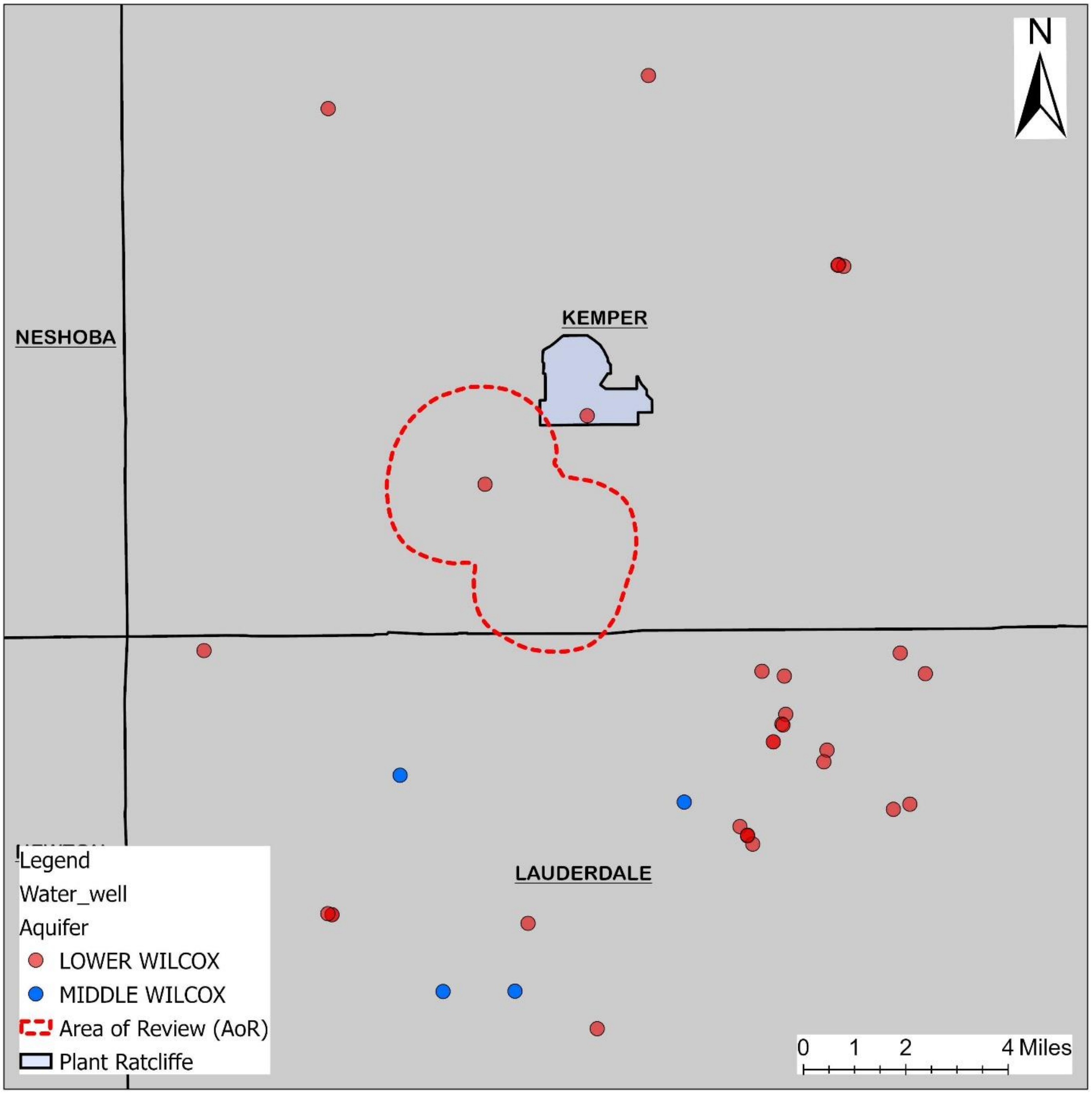

Figure 35. Shallow groundwater wells around the Kemper County Storage Complex

The Porters Creek clay and Selma Group together form an aquitard over 1,500 ft thick in Kemper County that isolates the Tertiary Wilcox aquifer from the underlying Cretaceous Eutaw-McShan aquifers. The Porters Creek clay is a shale interval in the Paleocene Midway group that forms a coarsening-upwards sequence that have been interpreted as regionally extensive marine shelf deposits, being traceable across the Gulf Coast Basin [70]. The Porters Creek consists of thick, massive carbonaceous clay, about 500 – 600 ft thick in Kemper County. In the Mississippi Interior Salt Basin, the Porters Creek clay acts as a confining unit that retains oil in fractured chalk reservoirs [71]. The top of the Cretaceous section is capped by the Selma Group chalk, which forms an extensive regional seal for oil and gas accumulations from the Eutaw Formation [72] [73] [74] [71]. The Selma is a ~900 ft succession of chalk and marl which represents a regionally extensive muddy carbonate ramp which bordered the Cretaceous sea in the Gulf of Mexico region [75].

The Eutaw-McShan aquifer consists of the hydrologically connected Eutaw and McShan strata. The aquifer crops out in northeastern Mississippi and northwestern Alabama and dips at about 35 to 40 feet per mile towards the axis of the Mississippi embayment in northern areas, and southwestward in southern areas. It is separated from the Wilcox aquifer by the Porters Creek clay (Midway) and Selma groups. Near the Kemper County Storage Complex, the Eutaw is 400 – 550 ft thick and at depths of 1500 – 3000 ft. The Eutaw marks the deepest USDW in Kemper County, with TDS concentrations of 1610 mg/L.

Recharge to the Eutaw-McShan occurs principally from precipitation but some recharge likely originates as vertical leakage from overlying and underlying aquifers [76] [77]. Discharge occurs to hydrologic lows at the outcrop, to the underlying Gordo aquifer, and to wells completed in the aquifer. TDS concentrations increase downdip, exceeding 10,000 mg/L in central Mississippi. Separating the Eutaw-McShan from the underlying Gordo aquifer is a clay / silt confining layer that is relatively thin but can locally exceed 175 ft of thickness [78]. This confining unit isolates the two aquifers, although the Eutaw-McShan may be recharged by the Gordo in parts of the down-dip area [78].

[70] Mancini et al. (1996). See Section B.1.c., footnote #11.

[71] Pashin, J. C. (2000). Revitalizing Gilbertown oil field: characterization of fractured chalk and glauconitic sandstone reservoirs in an extensional fault system (Vol. 168). Geological Survey of Alabama.

[72] Frascogna (1957). See Section B.4.c., footnote #42.

[73] Davis & Lambert (1963). See Section B.4.c., footnote #43.

[74] Galicki (1986). See Section B.1.d., footnote #18.

[75] Mancini et al. (1996). See Section B.1.c., footnote #11.

[76] Mallory (1993). See Section B.1.a, footnote #3.

[77] Strom, E. W., & Mallory, M. J. (1995). *Hydrogeology and simulation of ground-water flow in the Eutaw-McShan Aquifer and in the Tuscaloosa aquifer system in northeastern Mississippi* (Vol. 94, No. 4223). US Department of the Interior, US Geological Survey.

[78] Strom (1998). See Section B.7., footnote # 67.

The Gordo, Coker, and Massive sand aquifers of the Tuscaloosa Group and the underlying Lower Cretaceous aquifer constitute the regional Tuscaloosa Aquifer system. While the term “Aquifer System” is commonly used to describe the Tuscaloosa, the sand-rich aquifer zones are typically confined by relatively impermeable clay horizons that limit vertical communication between the individual aquifers, creating individual aquifers within the system.

The Gordo aquifer crops out in the northeastern portion of the State and dips at 35 to 40 feet per mile towards the axis of the Mississippi embayment (westerly to southwesterly). At 350 feet, the thickest part of the aquifer lies in downdip areas to the southwest, thinning to a feather edge in up-dip outcrop areas along the Mississippi-Alabama state line. The Gordo aquifer is recharged through precipitation at the outcrop and from the Coker and Eutaw-McShan aquifers. Discharge from the Gordo aquifer also occurs to the Coker and Eutaw-McShan aquifers, and to wells drilled in the formation [78]. Regional groundwater movement is westerly and southwesterly but has been modified locally near Tupelo and Columbus due to large withdrawals [79]. TDS concentrations increase downdip, with the limit of freshwater (10,000 mg/L) placed in the southern half of Kemper County [78].

The Coker aquifer underlies the Gordo aquifer and crops out in the northwestern portion of Alabama. The aquifer dips at 35 to 40 feet per mile towards the southwest. Total sand thickness ranges from 1 foot at the outcrop to about 350 feet in the downdip portions. The Coker is recharged primarily by precipitation on outcrop areas, but leakage between the adjoining Gordo and Massive sand formations may also provide recharge and discharge pathways to and from the aquifer. TDS concentrations increase downdip, exceeding 10,000 mg/L in the southwest corner of Kemper County [80].

The Massive sand aquifer underlies and is considered part of the Coker in updip areas, however, confining clay of up to 200 feet in thickness exists in western, downdip portions of the aquifer area, hydraulically isolating the two zones [80]. The Massive sand dips at 35 to 40 feet per mile towards the southwest. The aquifer ranges in thickness from its feather edge in eastern, updip regions to more than 350 feet in downdip portions of the Massive sand. The aquifer does not crop out at the surface and is recharged only through the overlying, hydrologically connected portions of the Coker aquifer. Discharge occurs to the underlying and overlying strata, and to wells

[79] Darden, D. (1984). *Potentiometric map of the Gordo Aquifer in northeastern Mississippi, November and December, 1982* (No. 83-4254).

[80] Strom (1998). See Section B.7., footnote # 67.

completed in the aquifer. TDS concentrations increase downdip, exceeding 10,000 mg/L near Plant Ratcliffe.

The Lower Cretaceous aquifer beneath the Massive sand aquifer does not outcrop in Mississippi. To the north and northeast of Plant Ratcliffe, the aquifer pinches out against Paleozoic rock. To the west, southwest, and south, in the downdip direction, the aquifer contains water with increasing TDS concentrations [80]. The aquifer dips about 35 to 40 feet per mile toward the west and southwest [80]. Well data indicates that total sand thickness within the study area ranges from about 1 foot where it pinches out against Paleozoic rocks in the northeast, to more than 1,000 feet [80], with the sand generally thickening downdip. The Lower Cretaceous aquifer receives recharge from the Massive sand aquifer in the up-dip area. The Lower Cretaceous aquifer is confined from the overlying Massive sand aquifer by clay and silt.

Within the AoR, groundwater is only utilized from the Wilcox aquifer. A total of 54 groundwater wells are listed within this area and are completed in either the Middle Wilcox or the Lower Wilcox aquifer. Maximum well depth is 480 feet below ground level and none of these wells penetrate the Porters Creek clay (Midway). The top of the Porters Creek clay is located more than 4,100 feet above the Paluxy injection interval.

B.8. Geochemistry [40 CFR 146.82(a)(6)]

B.8.a. Paluxy Formation Mineralogy (Solid-Phase Geochemistry – Injection Interval)

The mineralogy of the Paluxy Formation was investigated using Petrographic Microscopy and Scanning Electron Microscopy on thin sections cut from whole core in addition to X-Ray Diffractometry of powdered samples. The dominant framework grain composition comprises monocrystalline quartz with the polycrystalline quartz being the second most abundant. Quartz content in the Paluxy ranges from 65 - 95%. Potassium feldspars (e.g. Albite) constitute the next most abundant framework grain and ranges in concentration from 2 - 16%. Potassium feldspars are typically partially dissolved and clay coats on grains reveal remnant feldspars grains that have partially or completely altered to clays.

Lithic fragments have a similar abundance to potassium feldspar and include metamorphic rock fragments such as schist, quartzite, and chert with some igneous rock fragments. Accessory minerals include muscovite, biotite, and siderite. In addition, the Paluxy Formation contains minor amounts of calcite cement and pore-filling matrix clays such as smectite/illite and kaolinite. Paluxy sandstones predominantly plot as subarkose using the Folk (1980) Diagram [81] [82].

Continuum Scale Reactive Transport Modeling was conducted to simulate the geochemical reactions that would occur during CO_2 injection in the Paluxy Formation based on the injection interval mineralogy [83]. Modeling indicates an initial increase in porosity from 25 to 33% primarily due to calcite dissolution, and a subsequent decrease in porosity to 31% over a 20-year period as quartz precipitates. The modeling results indicate that the mineralogy of the injection zone is compatible with CO_2 and injection will slightly increase reservoir porosity due to minor calcite cement dissolution.

<u>B.8.b. Marine Tuscaloosa Shale (Solid-Phase Geochemistry – Confining Zone)</u>

XRD analysis and SEM imaging was conducted on samples of the Marine Tuscaloosa Shale to identify the mudstone mineralogy of the primary confining zone [84]. XRD analyses of core samples identified quartz silt and clay (kaolinite, illite, smectite) as the primary mineralogical compositions that make up the mudstone. The range in mineral abundances for the marine shale include quartz (26 - 60.9%), kaolinite (9.4 - 36%), smectite (0 – 33%), illite/mica (1 - 21.1%), mixed illite/smectite (10.4 – 12.5%), potassium feldspar (1 – 7%), chlorite (0.5 – 2.7%), calcite (0 – 2%), plagioclase (0 – 2%), pyrite (0 – 2%), and anatase (0.6 – 0.9%). Overall, the low abundance of reactive mineralogy (e.g. calcite) indicates that the confining zone is compatible with the CO_2 injectate.

<u>B.8.c. Pore-fluid Chemistry of the Injection Zone and Shallow USDWs</u>

Fluid sampling analyses establish the geochemistry of pore-fluids by reporting the total dissolved solids (TDS) in addition to measuring the concentration of cations and anions present in the formation brines. Formation pore-fluids were sampled using Core Laboratories™ Positive Displacement Bottom Hole Sampling (PDBHS) Tool from each reservoir within the injection zone at wells, Water Well No. 1, MPC 34-1, and MPC 10-4 (**Figure 11**). In addition, a fluid sample of lowest most USDW was collected from the Eutaw Formation at the Kemper County USDW

[81] Folk (1980). See Section B.4.f., footnote #54.

[82] Pashin et al. (2020). See Section A.1., footnote #1.

[83] Beckingham et al. (2020). See Section B.1.f., footnote #57.

[84] Pashin et al. (2020). See Section A.1., footnote #1.

Characterization Well. Eutaw Formation sample fluids were recovered from the characterization well by airlift pumping through a screened interval of well pipe at the formation depth.

The results of water quality analyses conducted on seven fluid samples recovered from the injection zone and lowest most USDW are indicated in **Table 8**. Within the injection zone, fluid sampling results confirm that saline brines saturate each geologic formation and all of the formations are well above the 10,000 mg/L USDW cutoff. Geochemical results show that the pore-fluid brines range in TDS from 18,604 mg/L in the most shallow portion of the injection zone (3,360 ft) to 107,196 mg/L in the deepest portion of the injection zone (5,183 ft). The Eutaw Formation has been identified as the deepest USDW over the project AOR. Sample analysis through this zone has confirmed this with a TDS concentration of 1,610 mg/L.

Table 8. Geochemical water quality results determined from fluid samples taken by the Positive Displacement Bottom Hole Sample Tool from four different characterization wells in Kemper County, Mississippi.

Formation	Sample ID	Well Name	Sample Depth (ft.)	Formation Pressure (psi)	Formation Temperature (°F)	TDS (mg/L)	pH
Eutaw	680-204221-1	Kemper County USDW Characterization Well	2,190 - 2,210	Not Reported	Not Reported	1,610	8.70
Lower Tuscaloosa Group	201801592-01	Water Well No. 1	3,360	1,400	100	18,791	7.32
Lower Tuscaloosa Group	201801592-02	Water Well No. 1	3,360	1,400	100	18,604	6.77
Washita-Fredericksburg	201801231-05	MPC 34-1	4,470	1,750	125	80,587	6.14
Washita-Fredericksburg	201801231-06	MPC 34-1	4,470	1,750	125	81,779	4.75
Paluxy	201901859-01	MPC 10-4	5,183	2,180	128	107,196	5.50
Paluxy	201901859-01-01	MPC 10-4	5,183	2,180	128	106,848	5.48

B.9. Other Information (Including Surface Air and/or Soil Gas Data, if Applicable)

B.10. Site Suitability [40 CFR 146.83]

The Mesozoic-Cenozoic section around Plant Ratcliffe in Kemper County, MS contains a 1.7-km succession of saline reservoir and sealing strata composing a CO_2 Storage Complex with exceptional reservoir properties and complex depositional architecture. The Injection zone is a ~2000 ft interval located in the Cretaceous section of Kemper County, from the top of the Lower Tuscaloosa Massive sand through to the base of the Paluxy Formation. The Tuscaloosa Marine shale is the primary confining zone that directly overlies the injection zone and acts as a regional confining unit throughout the Gulf of Mexico Basin that is capable of preventing vertical migration of CO_2 out of the injection zone. The Marine shale is a low-porosity (2 - 4%) low permeability (< 1 mD) unit composed of interbedded dark-gray shale, siltstone, and sandstone that modelling has shown will retain a CO_2 column height of 100m before any intrusion. The Massive sand is a saline storage zone that directly underlies the Marine shale and is composed of sandstone and conglomerate. The Washita-Fredericksburg interval contains interbedded sandstone and mudstone and is divided into two mudstone-dominated confinement intervals (the Upper and Basal Washita-Fredericksburg shales), and one sandstone-dominated saline storage zone (the “Big Fred” sand) that is situated in the middle of the Washita-Fredericksburg. The prospective injection interval is in the sands of the Cretaceous-aged Paluxy Formation. Paluxy sandstone porosity ranges from 26 – 33% and the permeability was measured at 1.8 D. The storage capacity of the injection interval is estimated at 4.28, 8.10, and 13.90 Mt/mi^2 for storage efficiency factors of 7.4, 14, and 24%, respectively. An injected CO_2 stream will be confined to the Paluxy Formation sands, and the overlying confinement intervals and primary confining zone prevent the vertical migration of the plume into the overlying USDWs in the Eutaw and above. The low abundance of reactive minerals (e.g. calcite) in the primary confining zone and injection interval demonstrate that these zones are compatible with the CO_2 injectate. The lack of faults, wells that penetrate the injection formation, and intensive seismic activity in Kemper County make the presence of secondary pathways for CO_2 plume migration highly unlikely. The Selma Group and Porters Creek clay of the Upper Cretaceous and Tertiary sections act as aquitards to prevent plume migration into the overlying Nanafalia and Naheola Formation aquifers. The regional continuity of the confinement intervals and lack of faults in the Cretaceous section of Kemper County demonstrates that CO_2 plume migration will be confined to the injection zone.

C. AoR and Corrective Action

AoR and Corrective Action GSDT Submissions
GSDT Module: AoR and Corrective Action ***Tab(s):*** All applicable tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Tabulation of all wells within AoR that penetrate confining zone ***[40 CFR 146.82(a)(4)]*** ☐ AoR and Corrective Action Plan ***[40 CFR 146.82(a)(13) and 146.84(b)]*** ☐ Computational modeling details ***[40 CFR 146.84(c)]***

The information and files submitted in the AoR and Corrective Action plan satisfy the requirements of **40 CFR 146.84(b)**. This plan addresses how the Area of Review (AoR) will be delineated and uses corrective action techniques to address all deficient artificial penetrations and other features that compromise the integrity of the confining zone above the injection zone. The AoR is created to encompass the entire region surrounding the Kemper County Storage Complex where USDWs may be endangered by injection activity. The AoR is delineated by the lateral and vertical migration extent of the CO_2 plume, formation fluids and pressure front in the subsurface. A computational model was built to model the subsurface injection of CO_2 into the Paluxy Formation in the Kemper County Storage Complex. The GEM simulator is used to assess the development of the CO_2 plume, the pressure front, and the long-term fate of the injection. The AoR is delineated by the full lateral and vertical extent of the CO_2 plume in the subsurface, and used to monitor where USDW's may be compromised by injection activity. Details of the computational modelling, assumptions that are made, and the site characterization data that the model is based on satisfies the requirements of **40 CFR 146.84(c).**

A list of wells that penetrate the confining zone is included to satisfy the requirements of **40 CFR 146.82(a)(4)**. This shows that all deficient artificial penetrations in the AoR that could serve as conduits for fluid flow out of the injection zone are properly managed through designated corrective action methods.

D. Financial Responsibility

Financial Responsibility GSDT Submissions
GSDT Module: Financial Responsibility Demonstration ***Tab(s):*** Cost Estimate tab and all applicable financial instrument tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Demonstration of financial responsibility ***[40 CFR 146.82(a)(14) and 146.85]***

The Financial Responsibility plan demonstrates the financial responsibility for corrective action on wells in the AoR, injection well plugging, PISC and site closure, and emergency and remedial response according to 40 CFR 146.85. Specifically for the Kemper County Storage Complex, no corrective action is anticipated as there are no penetrations into the confinement interval except for the project wells. Injection well plugging costs are given according to the Injection Well Plugging Plan and PISC and Site Closure costs are presented in cashflow tables within the Financial Responsibility Plan according to the testing and monitoring strategy outlined in the Testing and Monitoring Plan. The Emergency and Remedial Response Plan covers the costs of one (1) leakage event throughout the project life. For more details, refer directly to the Financial Responsibility Plan where the financial instrument(s) are outlined, and costs are presented in more detail on a per tonne and total cost basis.

E. Injection Well Construction

E.1. Well Design

The injection well is designed to accommodate the mass of CO_2 that will be delivered to the storage site, considering key characteristics of the CO_2 storage reservoir that affect the well design. This section illustrates the comprehensive analysis performed to comply with and exceed the EPA Class VI standards regarding the design of the casing, cement, and wellhead [40 CFR 146.86(a)].

E.2. Maximum Wellhead Injection Pressure

A nodal analysis was conducted to determine the required wellhead (i.e., injection) pressure for the CO_2 injection wells. The injection well site is designed to have an average operating injection rate of 75 MMSCF/D. This rate will be accomplished by 4 $^{1}/_{2}$-inch injection tubing with an average wellhead pressure (WHP) of 1,200 psia.

To arrive at the average operating injection pressure, Schlumberger's PIPESIM software was utilized to conduct a nodal analysis. Inputs for the analysis are displayed in **Figure 36**. The surface string with a 9.625-inch 47ppf LTC thread casing set at approximately 1,000 ft with a 7-inch 26 ppf VAM TOP long string casing set at 5,600 ft. The injection string is assumed to be 13Cr80. The schematic for casing nodal analysis is shown in the figure below with in inputs in Figure 2. Design parameters are as follows: formation pressure is set at 2,325 psia, the horizontal permeability is 2.5 Darcy, the ratio of vertical-to-horizontal permeability is 0.1, perforations are between 5,040 feet and 5,575 feet at 6SPF and 60-degree phasing, formation temperature is 135 degrees Fahrenheit, and the injection fluid is 100% CO_2.

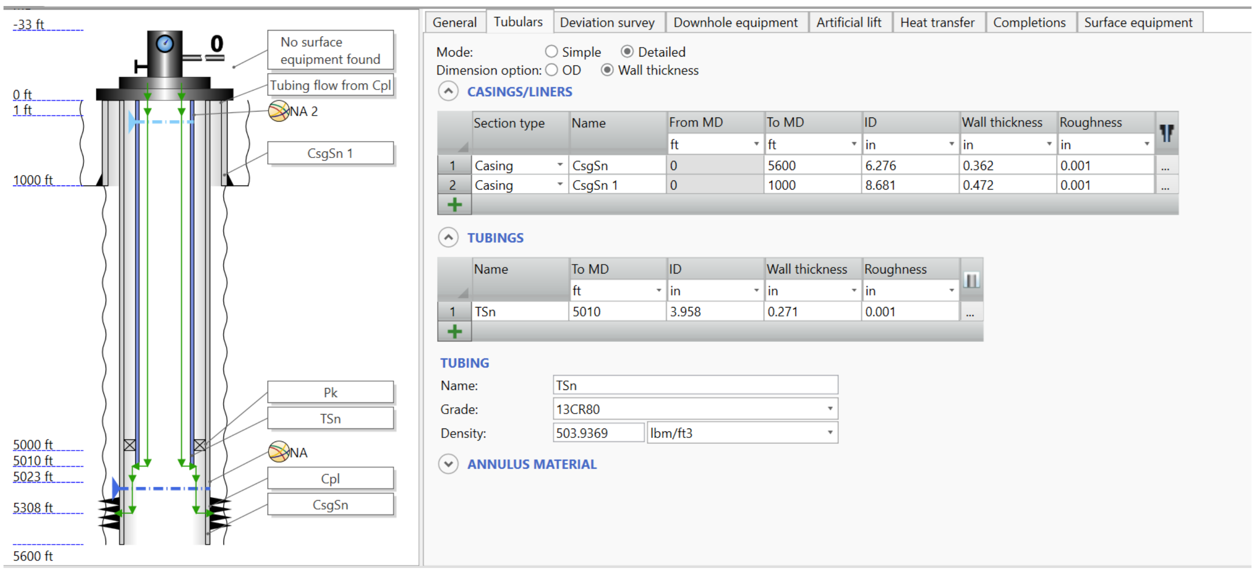

Figure 36. Nodal Analysis Design Schematic

To achieve the design flow rate, the injection pressure must be greater than the minimum bottom-hole pressure required to drive the CO_2 into the reservoir formation; however, the injection pressure must be maintained below the maximum safe pressure to avoid fracturing. The minimum bottom-hole pressure to provide the required flow rate into the Paluxy Formation was determined by subsurface reservoir modeling. The formation pressure has been determined to be 2,325 psia, and the outlet (bottomhole) pressure from the nodal analysis should exceed this value to achieve the injection rate. At the same time, the fracture pressure of 3,000 psia must never be exceeded. With WHP at 1,200 psia, the planned injection rate 75 MMSCF/D is achieved at the injection depth. The operating point displayed in **Figure 37** illustrates the operational flowrate that is obtained with 1,200 psia WHP.

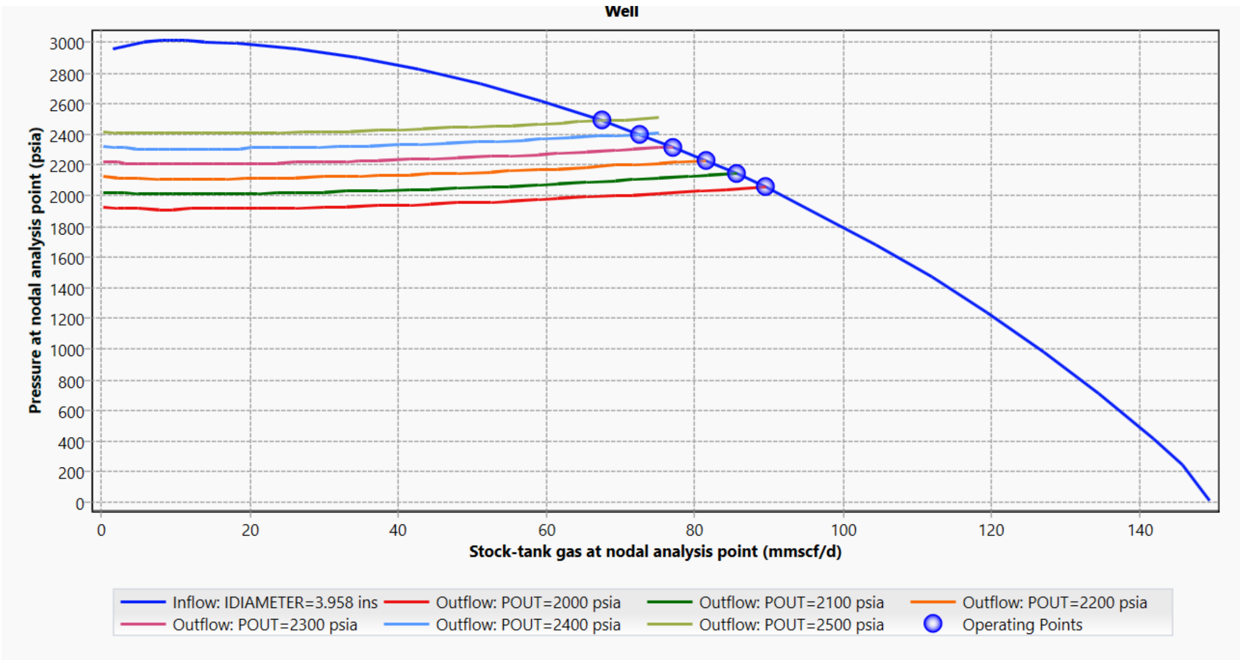

Figure 37. Inflow Performance Relationship (IPR) for 4.5 inch injection tubing

E.3. Casing Program

An injection well design has been developed to accommodate a 4 1/2-inch outer diameter (OD) tubing string, based on the nodal analysis presented in the previous section.

The injection well is designed to accommodate the 4 1/2-inch injection tubing, long string casing, surface casing, and conductor casing. The casing program is designed with material appropriate for the fluids and stresses encountered within the well [40 CFR 146.86(b)(1)]. This includes selection of corrosion-resistant stainless-steel material for the tubing long string casing, packer, and wellhead. In areas where the risk of CO_2 corrosion is not a concern, mild steel is utilized. These areas include all formations approximately 500 feet above the primary confinement interval.

Stresses were analyzed and calculated according to worst-case scenarios and casing specifications were selected accordingly. **Table 10** below summarizes the results of this analysis. The burst, collapse, and tensile strength of the casing were calculated according to the scenarios defined below and were dependent on fracture gradients, mud weight, depths, and minimum safety factors.

Table 10. Load Scenarios Evaluated

Load Name	Description	Casing String
Burst	The largest pressure differential occurs at either casing shoe or surface locations. The shoe scenario assumes formation fracture prior to casing rupture while the surface scenario assumes a gas kick while the wellbore contains drilling mud.	S
Collapse	For collapse consideration, the interior of the pipe is to be considered void and the consideration points are the casing shoe and the top of tail cement.	S
Burst	Cementing operation induces the largest rupture stresses, if lost circulation occurs during cementing, with all the tail cement in the pipe. The drilling fluid is used as a back-up.	P
Collapse	The greatest collapse stress occurs cementing of the casing with an interior column of mud to counteract the external cement slurries.	P
Burst	The injection process induces the maximum pressure onto the injection tubing and as such, represents the scenario of investigation.	T
Collapse	The design case for maximum loading occurs during annular pressure testing of the well, which assumes fluid inside the tubing is at a minimum specific gravity.	T
Tension	Tensile strength of the casing is governed by the entire weight of the string being analyzed while accounting for buoyancy effects.	S, P, T

S = surface casing; P = production or long-string casing; T = tubing

As demonstrated, the safety factors are sufficient in the worst-case scenarios to prevent migration of fluids into or out of USDWs or unauthorized zones (**Table 11**). The casing and tubing materials are designed to be compatible with the fluids encountered and the stresses induced throughout the sequestration project.

Table 11. Calculated Safety Factors for the Proposed Tubular Program

Tubular	Safety Factors		
	Burst (psi)	Collapse (psi)	Tension (lbs)

Surface	5.06	1.61	4.76
Long String	2.10	2.49	3.34

E.4. Casing Summary

The injection well design will include the following casing strings: a 24-inch-diameter conductor string set at a depth of approximately 60 ft below ground surface (BGS) inside a 28-inch borehole; a 16-inch-diameter surface string set at a depth of approximately 2,500 ft BGS inside a 20-inch borehole; a 9 5/8-inch-diameter long string set at a depth of approximately 5,700 ft BGS inside a 12 1/4-inch borehole; and a 4 1/2-inch-diameter deep (injection) tubing string set at an approximate depth of 5,040 ft BGS. All casing strings will be cemented to the surface. The borehole diameters are considered conventional sizes for the sizes of casing that will be used and should allow ample clearance between the outside of the casing and the borehole wall to ensure that a continuous cement seal can be emplaced along the entire length of the casing string. **Table 12** summarizes the casing program for the injection well. **Table 13** summarizes properties of each casing material.

Table 12. Borehole and Casing Program for the CO_2 Injection Well

Casing String	Casing Depth (Feet BGS)	Borehole Diameter (in.)	Casing Outside Diameter (in.)	Casing Material (weight/grade/ connection)	Coupling Outside Diameter (in.)
Conductor	60	28	24	157.53 lb/ft, Welded	24
Surface	0-2,500	20	16	109 lb/ft, J-55, STC	17
Long String	0-3,000	12.25	9.625	40 lb/ft, L-80, LTC	9.625
	3,000-5,700		9.625	40 lb/ft, L-80 CR13, LTC	9.625

Table 13. Properties of Well-Casing Materials

Casing String	Casing Material (weight/grade/connection)	Casing Outside/Inside/Drift Diameter (in.)	Burst (psi) Plain End	Collapse (psi)	Joint Tensile Strength (1,000 psia)
Conductor	157.53 lb/ft, Welded	24/ (0.5 in wall)	1,020	220	1,622
Surface	109 lb/ft, J-55, STC	16/14.688/14.5 (0.656 in wall)	3,950	2,560	1,116
Long String	40 lb/ft, L-80, LTC	9.625/8.835/8.679 (0.395 in wall)	5,750	3,090	727
	40 lb/ft, L-80 CR13, LTC	9.625/8.835/8.679 (0.395 in wall)	5,750	3,090	727
Tubing	12.6 lb/ft, L-80 CR13, EUE	4.5/3.958/3.833 (0.2575 in wall)	8,430	7,500	208.7

E.4.a. Conductor Casing

The conductor casing consists of 24-inch mild steel and provides the stable base required for drilling activities in unconsolidated sediment. Depending on wellsite conditions, this can be drilled and installed or driven directly. This section of casing is also cemented in place.

E.4.b. Surface Casing

The surface casing is 16-inch-diameter 109-lb/ft J-55 pipe with short thread couplings (STCs). The metallurgy of this casing string is carbon steel. Surface casing is to be cemented to surface, isolating the USDWs through which the string extends. Following the cement setting, a bond log is run to ensure a sufficient seal to prevent the migration of fluid into USDWs.

E.4.c. Long-String Casing

The long-string casing will be 9 5/8-inch-diameter pipe composed of two sections. Class VI rule dictates that the long-string shall extend from surface to the injection zone [40 CFR 146.86(b)(3)]. The uppermost section (approximately 3,000 ft) will be L-80 32-lb/ft carbon steel pipe with long thread couplings (LTCs); the lower section (3,000 to 5,700 ft) will be a corrosion-resistant alloy (e.g., 13% Cr95 stainless steel) having strength properties equivalent to or better than L-80 32-lb/ft pipe with LTCs.

E.4.d. Tubing

The tubing connects the injection zone to the wellhead and provides a pathway for sequestration of the CO_2 injectate. This design utilizes 4 1/2-inch 12.60 lb/ft L-80 CR13 tubing, which resists corrosion from the injected fluid. Based on the anticipated formation pressure, temperature, and stress, the grade of tubing was selected with the API specifications outline in **Table 14** and the safety factors were calculated as shown in **Table 15**. These safety factors represent sufficient quality standards to preserve the integrity of the injected fluid, the injection zone, and above USDWs. The annulus between the tubing and long-string casing will be filled with noncorrosive fluid described in detail throughout the "Annular Fluid" section in accordance with Class VI rule [40 CFR 146.88(c)].

Table 14. Calculated Safety Factors for the Proposed Injection Tubing

	Safety Factors		
Tubular	Burst (psi)	Collapse (psi)	Tension (lbs)
Tubing	4.38	1.98	5.13

E.5. Cementing Program

This section discusses the types and quantities of cement that will be used for each string of casing. The conductor, surface casing, and deep casing will be cemented to the surface in accordance with requirements of the Class VI regulation [40 CFR 146.86(b)(3)]. The proposed cement types and quantities for each casing string are summarized in **Table 15**.

Casing centralizers will be used on all casing strings to centralize the casing in the hole and help ensure that cement surrounds the casing along the entire length of pipe. Except for the conductor casing, a guide shoe or float shoe will be run on the bottom of the bottom joint of casing and a float collar will be run on the top of the bottom joint of casing. The conductor casing, due to its relatively short depth, doesn't require the use of a float or guide shoe to emplace cement.

Table 15. Cementing Program

Casing String	Casing Depth (ft)	Borehole Diameter (in.)	Casing O.D. (in.)	Cement Interval (ft)	Cement
Conductor Casing	150	38	30	0-150 (cemented to surface)	Class A with 2% CaCl2 (calcium chloride) and 0.25 lb/ sack cell flake; cement weight: 15.6 lb/ gal; yield: 1.18 ft3/sack; quantity: 821 sacks.
Surface Casing	600	26	20	0-600 (cemented to surface)	Lead-in: "Light" with 0.25 lb/sack cell flake; weight: 13.1 lb/gal; yield 1.69 ft3/sack; quantity: 374 sacks. Tail: Class A with 2% CaCl2 and 0.25 lb/sack cell flake; weight: 15.6 lb/gal; yield: 1.18 ft3/sack; quantity: 512 sacks.
Intermediate Casing	3,500	17.5	13.375	0-2,750	Stage 2 Lead-in: 65/35 Pozmix with 10% gel; weight 12.5 lb/gal; yield: 1.75 ft3/sack; quantity: 1,304 sacks. Stage 2 Tail: 50/50 Pozmix, no gel, 2% Cal Seal, 10% salt; weight: 14.1 lb/gal; yield: 1.26 ft3/sack; quantity: 414 sacks.
				2,750-3,500	Stage 1 Lead-in: Class A with 10% Cal Seal and 10% salt; weight: 14 lb/gal; yield: 1.6 ft3/sack; quantity: 326 sacks. Stage 1 Tail-In: 50/50 Pozmix, no gel, 2% Cal Seal, 10% salt, 0.75% dispersant, 0.25% defoamer; weight: 16.7 lb/gal; yield 1.1 ft3/sack; quantity: 740 sacks.
Long Casing String	4,500	9.625	12.25	0-4,500 (cemented to surface)	Lead-in: 65/35 Pozmix with 2% gel; weight: 12.5 lb/gal; yield: 2.01 ft3/sack; quantity: 585 sacks. Tail: EverCRETE CO2- resistant cement (or similar); weight: 15.82 lb/gal; yield: 1.12 ft3/sack; quantity: 595 sacks.

See acronym list for definition of abbreviations used in this table.

E.6. Annular Fluid

The annular space above the packer between the 9 5/8-inch long-string casing and the 5 1/2-inch injection tubing will be filled with fluid to provide a positive pressure differential to stabilize the injection tubing and inhibit corrosion.

The annular fluid will be a dilute salt solution such as potassium chloride (KCl), sodium chloride (NaCl), calcium chloride ($CaCl_2$), or similar solution. The fluid will be mixed onsite from dry salt and freshwater, or it will be acquired pre-mixed. The fluid will also be filtered to ensure that solids do not interfere with the packer or other components of the annular protection system. The final choice of fluid type will depend on availability.

The annulus fluid will contain additives and inhibitors including a corrosion inhibitor, biocide (to prevent growth of harmful bacteria), and an oxygen scavenger. Example additives and inhibitors are listed below along with approximate mix rates:

- TETRAHib Plus (corrosion inhibitor for carbon steel tubulars [i.e., casings, tubing]) – 10 gal per 100 bbl of packer fluid
- CORSAF™ SF (corrosion inhibitor for use with 13Cr stainless steel tubulars or a combination of stainless steel and carbon steel tubulars) – 20 gal per 100 bbl of packer fluid
- Spec-cide 50 (biocide) – 1 gal per 100 bbl of packer fluid
- Oxban-HB (non-sulfite oxygen scavenger) – 10 gal per 100 bbl of packer fluid.

These products were recommended and provided by Tetra Technologies, Inc., of Houston, Texas. Actual products may vary from those described above.

E.7. Wellhead

The wellhead will consist of the following components, from bottom to top:

- 20-3/4-in. x 13-3/8-in., 3,000-psi casing head
- 13-5/8-in. x 9-5/8-in, 5,000-psi casing head
- 11-in. x 4-1/2-in., 5,000-psi tubing head
- 4-1/2-in. 5,000-psi full-open master control gate valve
- 4-1/2-in. 5,000-psi automated tubing flow control valve
- 4-1/2-in. 5,000-psi cross with one (1) 4-1/2-in., 5,000-psi blind flange
- 4-1/2-in. 5,000-psi automated tubing flow control valve
- 4-1/2-in. x 2-7/8-in., 5,000-psi top flange and pressure gauge.

The wellhead injection configuration will be composed of materials that are designed to be compatible with the injection fluid. In general, all components that encounter the CO_2 injection fluid will be made of a corrosion-resistant stainless steel alloy. Because the CO_2 injection fluid will be very dry, use of stainless steel components for the flow-wetted components is a conservative measure to minimize corrosion and increase the life expectancy of this equipment. Materials that will not have contact with the injection fluid, such as the surface casing and shallow portion of the long string casing, will be manufactured of carbon steel. A preliminary materials specification for the wellhead injection configuration assembly is described in **Table 16** using material classes as defined in American Petroleum Institute (API) Specification 6A (Specification for Wellhead Configuration). A summary of material class definitions is provided in **Table 17**. The final wellhead injection configuration materials specification may vary slightly from the information given below due to product availability. An illustration of the wellhead configuration is provided in **Figure 38**.

Table 16. Materials Specification of Wellhead and Christmas Tree

Component		Material Class[a]
Casing Head Housing (for 20-in. surface casing)		DD, EE
Casing Head Spool (for 13-3/8-in. intermediate casing	Casing spool (20-3/4 in. 3K X 13-5/8 5K)	AA, BB, DD, EE
	Casing hanger (20 in. X 13-3/8 in.)	AA, DD
Tubing Spool Assembly (for 9-5/8-in. long-string casing)	Spool	AA
	Casing hanger	AA, DD
Christmas Tree	Tubing head adapter	DD, EE
	Manual gate valve	BB
	Pneumatic actuated gate valves (2)	BB
	Tubing hangar (for 4-1/2-in. tubing)	CC

[a] When multiple classes are given, the highest class applies. Cameron uses this convention because not all components are available in all class types.

Table 17. Material Classes from API 6A (Specification for Wellhead and Christmas Tree Equipment)

API Material Class	Body, Bonnet, End & Outlet Connections	Pressure Controlling Parts, Stems, & Mandrel Hangers
AA – General Service	Carbon or alloy steel	Carbon or low-alloy steel
BB – General Service	Carbon or low-alloy steel	Stainless steel
CC – General Service	Stainless steel	Stainless steel
DD – Sour Service[a]	Carbon or low-alloy steel[b]	Carbon or low-alloy steel[b]
EE – Sour Service[a]	Carbon or low-alloy steel[b]	Stainless steel[b]
FF – Sour Service[a]	Stainless steel[b]	Stainless steel[b]
HH – Sour Service[a]	Corrosion-resistant alloy[b]	Corrosion-resistant alloy[b]

Source: Cameron Surface Systems, Houston, Texas
[a] As defined by National Association of Corrosion Engineers (NACE) Standard MR075.
[b] In compliance with NACE Standard MR0175.

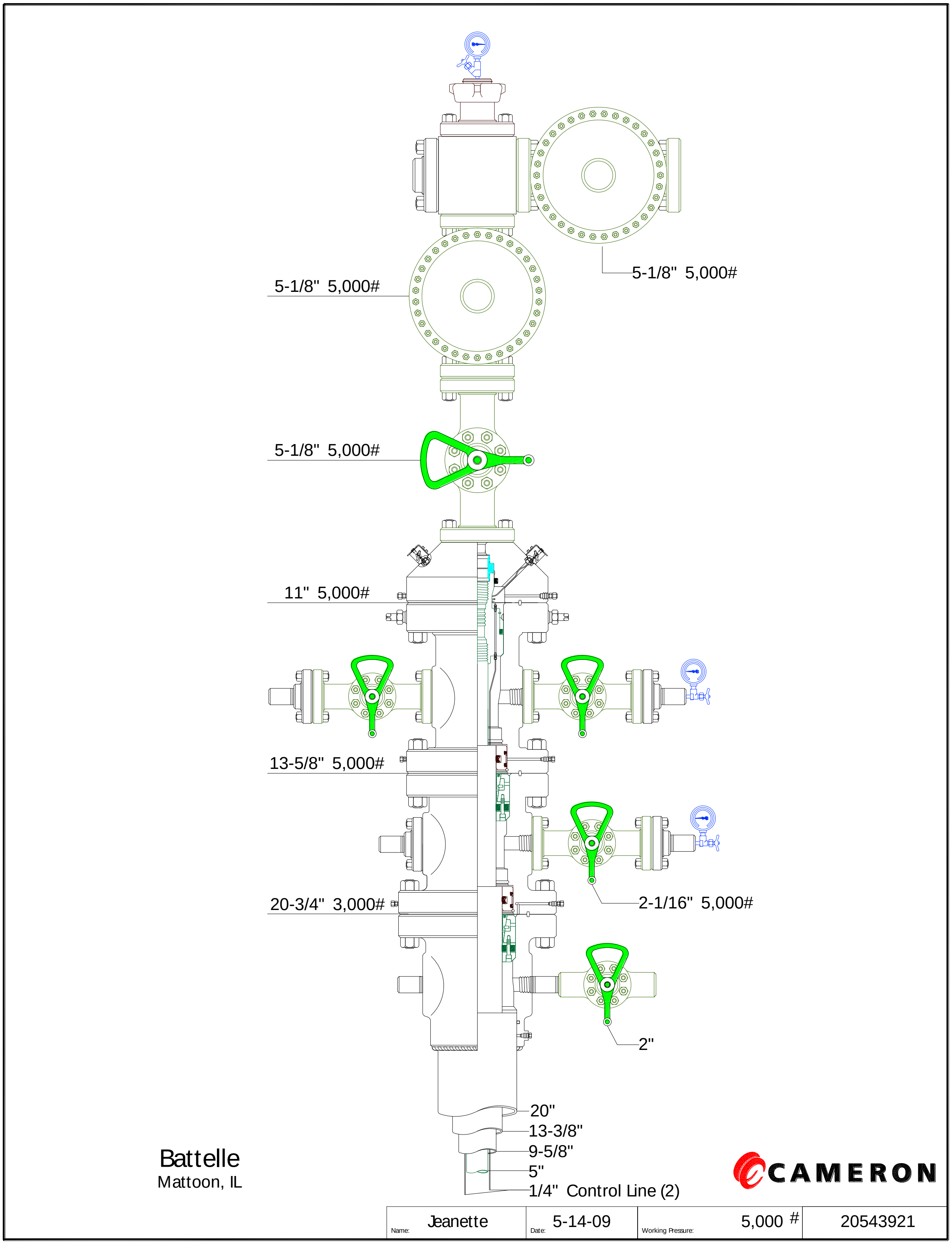

Figure 38. Illustration of the Wellhead Configuration.

E.8. Perforations

The long-string casing will be perforated across the Paluxy Sandstone with deep-penetrating shaped charges. The exact perforation interval will be determined after the well is drilled and characterized with geophysical logging, core analyses, and hydrogeologic testing. The planned perforations will be set between 5,040 feet and 5,575 feet with 6 shots-per-foot and 60-degree phasing. Perforation diameters are 0.5 inches and lengths are 15 inches.

E.9. Schematic of the Subsurface Construction Details of the Well

A schematic of the injection well is shown in **Figure 39**. As discussed in the previous sections, the injection well(s) will include the following casing strings: a 24-in.-diameter conductor string set at a depth of approximately 60 ft BGS; a 16-in.-diameter surface string set at a depth of approximately 2,500 ft BGS; a 9-5/8-in.-diameter long string set at an approximate depth of 5,700 ft BGS. All depths are preliminary and will be adjusted based on additional characterization data obtained while drilling the CO_2 injection wells. The conductor, surface and long casing strings will be cemented to surface.

The purpose of the conductor string is to provide a stable borehole across the near-surface, unconsolidated sediment deposits before drilling the remaining deeper casing strings and to help protect the USDWs. The surface string will extend across the uppermost geologic layers and will help to further isolate and protect the USDWs. The long string casing will extend to approximately 70 feet below the setting depth to allow proper emplacement of cement.

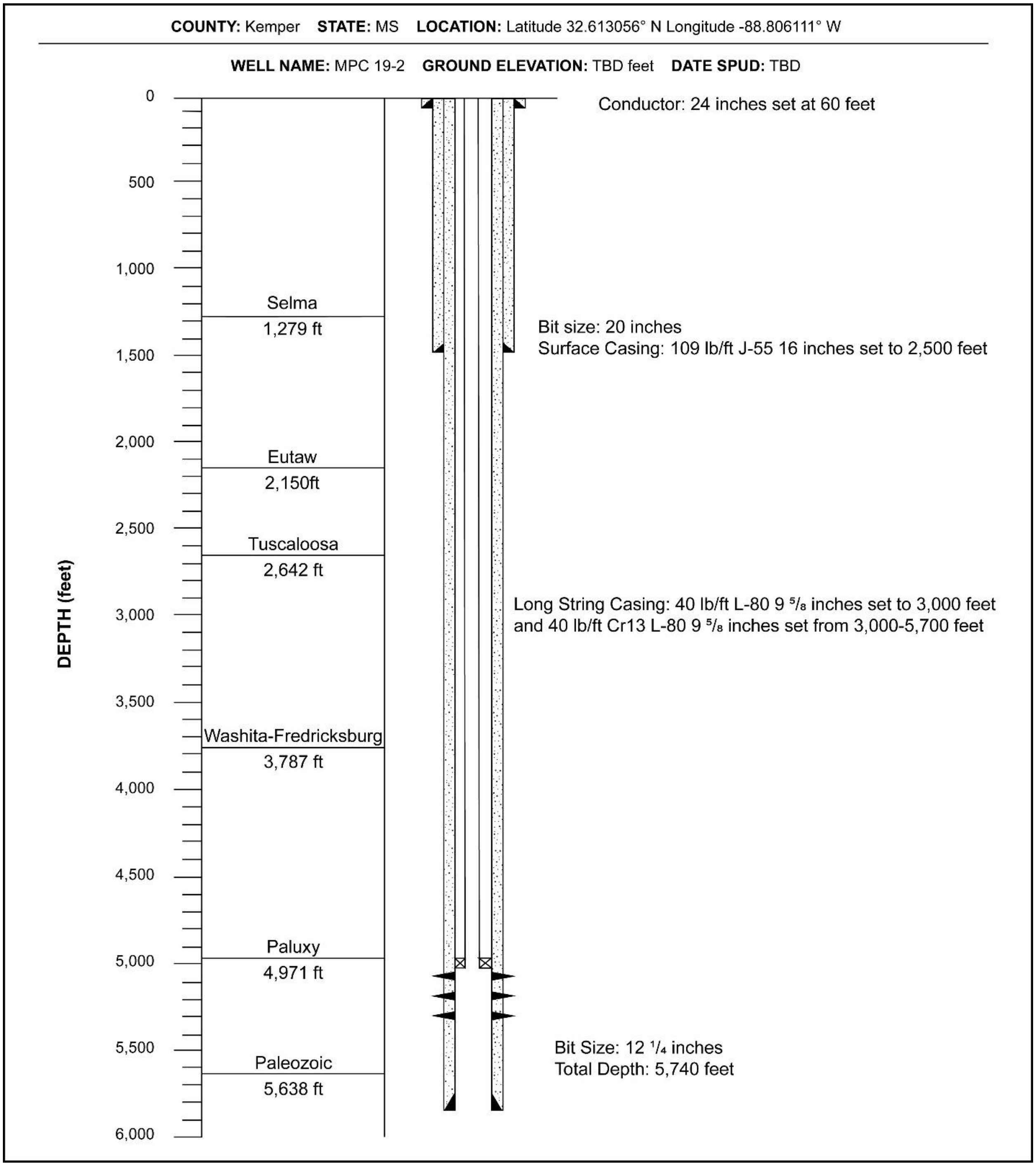

Figure 39. Preliminary Injection Well Schematic

F. Pre-Operational Logging and Testing

Pre-Operational Logging and Testing GSDT Submissions
GSDT Module: Pre-Operational Testing ***Tab(s):*** Welcome tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Proposed pre-operational testing program ***[40 CFR 146.82(a)(8) and 146.87]***

The pre-operational testing and logging plan is designed to establish an accurate baseline dataset of pre-injection site conditions as well as verify depths and physical characteristics of geologic formations germane to the injection and confining zones, and ensure that injection well construction satisfies requirements outlined in section 146.86.

During the drilling and construction phase of the project, appropriate log suites, surveys, and tests will be deployed to verify the depth, thickness, porosity, permeability, and lithology of pertinent geologic formations, as well as the salinity of formation fluids within them.

Deviation checks will be performed during drilling at frequent intervals to keep track of the borehole location in the subsurface and serve as a reference for steering purposes in order to achieve as near to vertical wellbore as possible. These checks will also assist in assuring that avenues for vertical fluid movement are not created in the form of diverging holes while drilling.

Resistivity, spontaneous potential, and caliper logs will be run before casing is run. A cement bond log along with variable density and temperature logs will be run to evaluate radial cement quality once the casing is cemented in place.

At minimum, resistivity and spontaneous potential logs, along with porosity, caliper, gamma ray, and fracture finder logs will be run prior to the installation of the long string casing. Cement bond, variable density, and temperature logs will also be run after long string casing is cemented in place to verify the quality of the cement job.

Internal and external mechanical integrity of the injection wells will be tested to demonstrate the absence of leaks in the wellbore that could result in migration of CO_2 out of the injection zone. An annular pressure test will be performed within 24 hours of cementing casing.

Core samples have been taken of the confining and injection zones while drilling the characterization and observation wells. Analysis of these cores was coupled with analysis of well logs as part of the geologic site characterization study. Results demonstrated consistency of key aspects of the subsurface geology, including presence, thickness, porosity, and permeability of the reservoir across the AoR.

Fluid samples were collected from the injection zone in a well approximately 4 miles from the planned injection location. Fluid sample analysis established baseline measurements for fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone.

Upon completion and before operation, hydrogeologic characteristics of the injection zone will be determined by performing a composite injectivity evaluation test in the injection interval to determine the large-scale transmissivity through the reservoir.

G. Well Operation

The injection well will be operated to handle an average of 4,000 metric tons/day (75 MMSCF/day) of CO_2 annually. The injection well operation program described in this document seeks to safely inject CO_2 into the Paluxy reservoir while avoiding unintended geomechanical effects and maintaining well integrity. Operational details provided in this document satisfy 40 CFR 146.82 (a) (7) and (10). Operational design described in this document has been developed to adhere to requirements set forth in 40 CFR 146.88.

G.1. Proposed Characteristics of Carbon Dioxide Stream [40 CFR 146.82(a)(7)(iii) and (iv)]

CO_2 injected in this project will be sourced from MPC's Plant Ratcliff and Plant Daniel facilities. The design basis for the capture facility is (80-90%) percent availability (i.e., 292-329 days/yr). Therefore, the daily CO_2 flow rate when the system is operational will be approximately 4,000 MT/d (1.45 MMT injected over 365 days). The planned injection period of the project is 30 years; therefore, a total of 43.5 MMT of CO_2 will be injected at the Kemper County CO_2 storage site using injection well MPC 19-2. **Table 18** lists the physical and chemical characteristics of the CO_2 stream at the injection wellhead.

Table 18. CO_2 Injection Stream Composition

Attribute	Value	Unit
Average Annual Flow Rate	4,000	Metric tons/day
Average Pressure at Wellhead	1,200	Psia
Average Temperature at Wellhead	65	oF
CO_2	99.4	%
Nitrogen (N_2)	0.3	%
Hydrogen Sulfide (H_2S)	<< 0.01 (<< 100 ppm)	%
CH_4/C_2H_6	0.3	%
Water (H_20)	< 0.05 (<50 ppm)	%

G.2. Corrosiveness of the Carbon Dioxide Stream

The proposed injection stream shall contain less than 50 ppm of water as indicated in Table 1. Consequently, the project team does not anticipate CO_2-induced corrosion affecting well components as noted by the U.S. EPA[85]. MPC will, however, monitor for potential corrosion induced by the injectate as outlined in the Testing and Monitoring Plan.

G.3. Operational Procedures [40 CFR 146.82(a)(10)]

Operational procedures described here were developed to factor in the thermohydraulic performance of the MPC 19-2 injection well based on wellbore design parameters described in the Injection Well Construction Plan . This analysis and ensuing calculations are described in this section.

G.3.a. Operational Conditions

Operational conditions were calculated using Schlumberger's PIPESIM, a steady-state multi-phase flow simulator. Reservoir pressure and CO_2 flow rates were supplied as inputs to the simulator while injection tubing size was determined using a nodal analysis. The reservoir pressure value supplied as input is designed to be lower than the fracture pressure of the reservoir. These inputs are summarized in **Table 19**. Calculations in PIPESIM consider the pressure-volume-temperature (PVT) properties of pure CO_2 flowing through a 4-½ inch tubing to

[85] United States Environmental Protection Agency, 2012. Underground Injection Control (UIC) Program Class VI Well Construction Guidance. Published May 2012.

a bottomhole depth of 5,010 ft. Pressure along the wellbore was modeled to be impacted by surface roughness (friction), hydrostatic effects, and fluid velocity.

Table 19. Inputs to Wellbore Calculations in Pipesim ®

Input Parameter	Value	Unit
Injection Zone Permeability	2,500	mD
Injection Zone Temperature	135	°F
Damaged Permeability Ratio	1	
Skin Permeability Ratio	1	
Injection Zone Top Depth	5,047	ft
Injection Zone Bottom Depth	5,578	ft
CO_2 Purity	99.4	%
Perforations (60-degree phase)	6	Shots per Foot
Reservoir Pressure (assumed to be maximum injection pressure encountered during injection as determined from AOR modeling results)	2,328	Psia

Please note that the fracture pressure for the Paluxy formation is 3,276 psig, which is calculated using a fracture pressure gradient of 0.65 psi/ft. The design reservoir pressure of 2,328 psi is less than 90% of the fracture pressure (2,948 psi) in accordance with 40 CFR 146.88 (a). **Table 20** summarizes operational parameters as determined by PIPESIM analysis. These parameters are likely to stay consistent throughout the injection phase. The injection well will be continually monitored for pressures and injection volumes to stay compliant with permitted quantities. Details of monitoring are included in the Testing and Monitoring Plan.

Table 20. Proposed operational procedures

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure		
Surface	1,800	Psia

Parameters/Conditions	Limit or Permitted Value	Unit
Downhole	3,000	Psia
Average Injection Pressure		
Surface	1,200	Psia
Downhole	2,380	Psia
Maximum Injection Rate	82 (4,338)	MMSCF/day (Tonnes/day)
Average Injection Rate	75 (4,000)	MMSCF/day (Tonnes/day)
Maximum Injection Volume and/or Mass	47.5 (898)	MMT (BCF)
Average Injection Volume and/or Mass	43.5 (822)	MMT (BCF)
Minimum Annulus Pressure at Surface	200	Psia
Minimum Annulus Pressure/Tubing Differential Above Packer	100	Psi

Injection is only planned to occur through the innermost tubing. Injection between the outermost casing protecting USDWs and the wellbore is prohibited in compliance with 40 CFR 146.88 (b), and the well will be monitored for potential annular leaks and external mechanical integrity as outlined in the Testing and Monitoring Plan.

The annular fluid will be a dilute salt solution such as potassium chloride (KCl), sodium chloride (NaCl), calcium chloride ($CaCl_2$), or similar. The fluid will be mixed onsite from dry salt and good quality (clean) freshwater, or it will be acquired pre-mixed. The fluid will also be filtered to ensure that solids do not interfere with the packer or other components of the annular protection system. The final choice of the type of fluid will depend on availability. The annulus fluid will contain additives and inhibitors including a corrosion inhibitor, biocide (to prevent growth of harmful bacteria), and an oxygen scavenger. The annulus pressure will be maintained at 200 psi higher than the operating pressure as outlined in **Table 20**. This will satisfy annular fluid and differential pressure requirements set forth in 40 CFR 146.88 (c). Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing/casing annulus is disassembled for maintenance or corrective procedures, the owner or operator must always maintain mechanical integrity of the injection well.

G.3.b. Operational Protocols

Startup

MPC will initiate injection as detailed in **Table 21** and conduct operational monitoring of the injection site pursuant to 40 CFR 146.90 (b). Specific details of the startup protocol are outlined below.

A multi-stage startup procedure will be implemented in conjunction with surface and downhole pressure and temperature gauges in the injection well (MPC 19-1), as well as in-zone and above-zone monitoring wells.

During the start-up period the permittee will submit a daily report summarizing and interpreting the operational data. At the agency's request, the permittee will schedule a conference call as needed to discuss the operational data.

A series of successively higher injection rates have been determined as shown in the table below, and the elapsed time and pressure values are read and recorded for each rate and time step. Each rate step will last 24 hours. At no point during the procedure will the injection pressure exceed the maximum permitted bottomhole injection pressure (3,000 psia).

Table 21. Proposed operational procedures

Rate (Tonnes per day)	Duration (Hours)	Precent of Maximum Injection Rate (%)
668	24	16.7
1,332	24	33.3
2,000	24	50
2,668	24	66.7
3,332	24	83.3

Injection rates will be controlled by starting an additional compressor (fix volume with no spillback); thus, the flow will remain constant throughout the duration of the step rate period. Injection rates will be measured (using the Coriolis flow meter) and data will be recorded. Surface and downhole pressure and temperatures will be measured, and data will be recorded in the monitoring wells. During the startup period, a plot of injection rates and the corresponding stabilized pressure values will be graphically represented. During the start-up period, the project team will look for any evidence of anomalous pressure behavior. If anomalous pressure behavior is observed during the start-up period, the project team may conduct additional logging and modify the injection rate to better characterize the anomaly. If during the start-up period, the project team determines that anomalous pressure behavior indicates formation fracturing, injection will be stopped, and the line valve closed allowing the pressure to bleed-off into the injection zone. The instantaneous shut-in pressure (ISIP) will be measured, and the pressure data will be reviewed for event signatures. The permittee will notify the agency within 24 hours of the determination. The permittee will consult with the agency before initiating further injection.

Shutdown

MPC will install alarms and automatic surface shut-off systems that will be designed to monitor operating parameters such as injection rate, injection pressure, annulus pressure in compliance with 40 CFR 146.88 (e) (2). Automatic shutdown will be triggered under the following three conditions:

1. Annular fluid pressure drops below the permitted annular pressure.
2. CO_2 injection pressure exceeds maximum permitted injection pressure.
3. CO_2 injection rate exceeds maximum permitted injection rate (volume and/or mass).

If a shutdown is triggered or a loss of mechanical integrity is discovered, MPC shall immediately investigate and identify as expeditiously as possible the cause of the shutoff. If, upon such investigation, the well appears to be lacking mechanical integrity, MPC will:

1. Immediately cease injection.
2. Shut in well (close flow valve).
3. Vent CO_2 from surface facilities.
4. Take all steps reasonably necessary to determine whether there may have been a release of the injected CO_2 stream or formation fluids into any unauthorized zone.
5. Notify the Director within 24 hours.
6. Implement appropriate remedial actions (in consultation with the UIC Program Director).

7. Restore and demonstrate mechanical integrity to the satisfaction of the Director prior to resuming injection.
8. Reset automatic shutdown devices.
9. Notify the Director when injection can be expected to resume.

H. Testing and Monitoring

Testing and Monitoring GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Testing and Monitoring tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Testing and Monitoring Plan ***[40 CFR 146.82(a)(15) and 146.90]***

The Testing and Monitoring Plan describes how Mississippi Power Company (MPC) will monitor the Kemper County Storage Complex site, pursuant to 40 CFR 146.90, for the duration of the injection phase of this project. This plan will serve to demonstrate that the well is operating as planned, that the sequestered Carbon Dioxide (CO_2) plume and pressure front are moving as predicted and ensure that the CO_2 plume does not become a contamination risk to underground sources of drinking water (USDWs). Monitoring data collected will also be used to validate and adjust geological models used to predict the movement of CO_2 within the storage zone to support AoR re-evaluations.

Analysis of the CO_2 stream will be conducted at a frequency sufficient to generate data that is representative of its physical and chemical characteristics.

Continuous recording devices will be installed and used to monitor injection parameters including pressure, rate, and volume. Annular pressure between tubing and long string casing, as well as the annulus fluid volume added will also be monitored.

Well materials will be monitored and assessed on a quarterly basis for loss of mass, thickness, cracking, pitting, or other signs of corrosion. Sample material coupons will be placed in contact with the CO_2 stream and/or the CO_2 stream will be routed through a loop constructed from the same material used in well construction. Materials analysis will be compared with standards outlined in section 146.86(b) to ensure that all physical parameters continually meet or exceed minimum requirements for material strength and performance.

Groundwater quality and chemistry will be monitored frequently above the confining zone for any changes that may be resultant from CO_2 movement from the reservoir through the confining zone.

An external mechanical integrity test as outlined by section 146.89(c), will be performed at least annually until the injection well is plugged, or more frequently if requested by the Director.

A pressure fall-off test will be performed at minimum once every five years or as often as is requested by the Director.

The spatial nature and extent of the CO_2 plume, along with the presence or absence of pressure within the plume front margin will be monitored.

This testing and monitoring plan will be reviewed periodically, at minimum every 5 years. The plan will be adjusted accordingly to meet any changes to the facility or site conditions over time. Amended plans will be sent to the Director for approval as outlined in the permit modification requirements in sections 144.39 or 144.41 as appropriate.

I. Injection Well Plugging

Injection Well Plugging GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Injection Well Plugging tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Injection Well Plugging Plan ***[40 CFR 146.82(a)(16) and 146.92(b)]***

The mechanical integrity of the well must be demonstrated after CO_2 injection and prior to the plugging of the well to ensure no pathway has been established between the injection zone and the underground sources of drinking water (USDWs) or ground surface according to **40 CFR 146.82(a)(16)** and **40 CFR 146.92(b)**. Mechanical integrity testing requires a temperature log, noise log, or an activated-oxygen log to be run in the well. MPC will utilize a temperature log that will be run over the entire depth of the injection well to ensure fluid is not migrating outside of the injection interval. Further, this data will be compared to the pre-injection and operational phases of the project. Bottomhole pressure measurements will be recorded during the project, and the post-injection bottomhole pressure will be utilized to select a brine weight to maintain well control during logging activities. Additionally, this data will inform the cement weight for plugging operations. MPC will utilize full wellbore cement coverage to ensure containment of injection fluids and protection of USDWs. The injection well will be plugged with corrosion-resistant (EverCRETE or similar) cement across the injection interval and above the confinement interval and Class A cement from that point to surface. Following plugging, the casing will be cut off below ground surface and have a steel cap welded across the top. For more specific information, please refer to the *Injection Well Plugging Plan*.

J. Post-Injection Site Care (PISC) and Site Closure

PISC and Site Closure GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** PISC and Site Closure tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ PISC and Site Closure Plan ***[40 CFR 146.82(a)(17) and 146.93(a)]***
GSDT Module: Alternative PISC Timeframe Demonstration ***Tab(s):*** All tabs (only if an alternative PISC timeframe is requested) Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Alternative PISC timeframe demonstration ***[40 CFR 146.82(a)(18) and 146.93(c)]***

This chapter presents an overview of the Post-Injection Site-Care (PISC) and Site-Closure plan for the Kemper County Storage Complex pursuant to 40 CFR 146.82(a)(17) and 146.93(a). The PISC phase will begin when all CO_2 injection ceases and ends with site closure. Class VI Rule requires the demonstration of protection of USDWs throughout the PISC phase, and of non-endangerment for site closure. This plan describes the post-injection modeling that was completed to determine the pressure differential, position of the CO_2 plume, and to predict CO_2 migration. Additionally, there is a detailed description of the post-injection monitoring plan and the site-closure plan. Post-injection computational modeling was completed to predict CO_2 migration, determine pre- and post-injection pressure differentials and the overall Area of Review

(AoR) of the Kemper County Storage Complex. The numerical reservoir model used for calculating the AoR was also used for the post-injection site-care, and site-closure analysis.

The predicted positions of the CO_2 storage zone and pressure front at the end of 30 years of injection, 10 years after injection, and 20 years after injection were simulated in the model. The simulation indicates that the CO_2 plume would remain within 2.5 miles from the injection well at the time of site closure. Most of the CO_2 mass is concentrated around the injection well with some thin streaks of CO_2 extending further away to the northeast of the injection wells in the up-dip direction. Based on the model, it is estimated that there is not sufficient hydrostatic pressure in the injection zone to push fluids into or interact with the lowermost USDW, which is the Eutaw formation.

K. Emergency and Remedial Response

Emergency and Remedial Response GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Emergency and Remedial Response tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Emergency and Remedial Response Plan ***[40 CFR 146.82(a)(19) and 146.94(a)]***

The Emergency and Remedial Response Plan (ERRP) details actions that Mississippi Power Company (MPC) shall take to address movement of the injection fluid or formation fluid in a manner that may endanger an underground source of drinking water (USDW) during the construction, operation, or post-injection site care periods, pursuant to **40 CFR 146.82(a)(19) and 146.94(a)**. Examples of potential risks include: (1) injection or monitoring well integrity failure, (2) injection well monitoring equipment failure, (3) natural disaster, (4) fluid leakage into a USDW, (5) CO_2 leakage to USDW or land surface, or (6) an induced seismic event. In the case of one of the listed risks, site personnel, project personnel, and local authorities will be relied upon to implement this ERRP. MPC will communicate to the public about any event that requires an emergency response to ensure that the public understands what happened and whether there are any environmental or safety implications. This will include a detailed description of what happened, any impacts to the environment or other local resources, how the event was investigated, what actions were taken, and the status of the remediation. The ERRP will need to be reviewed at least once every five years following it approval, within one year of an area of review (AoR) reevaluation, within the timeframe indicated by the UIC Program Director following any significant changes to the injection process or the injection facility, or an emergency event, or as required by the permitting agency. Periodic training will be provided to well operators, plant safety and environmental personnel, the plant manager, plant superintendent, and corporate communications to ensure that the responsible personnel have been trained and possess the required skills to perform their relevant emergency response activities described in the ERRP.

L. Other Information